6.3 Analysis of Alternative: An Owner with Thermal Plants with the Potential to Exercise Market Power

California's electric market has experienced an extraordinary summer, leading the Commission to open an investigation into the wholesale market where the question of anticompetitive behavior and the possibility of the exercise of undue market power, among other things, are being addressed.[37] Some parties in Pacific Gas and Electric Company's hydroelectric divestiture proceeding have also served testimony regarding the potential to operate the hydroelectric assets in ways that could constitute the exercise of market power. Even Pacific Gas and Electric Company has specifically attempted to address this possibility by including a "market power mitigation" agreement with the ISO in its Proposed Settlement.[38] Given the experience of this summer, the Commission needs to better understand the potential for the owner or owners of the hydroelectric generating assets to exercise undue market power. In addition, the Commission needs to understand the ability of other market participants (not necessarily an owner of a hydroelectric or other generating facility) to exercise market power.

Attempts to exercise market power could lead to hydroelectric system operations that deviate from the operations modeled in this EIR for the No Project, PowerMax, and WaterMax scenarios, and such deviations could have significant adverse environmental effects. The preparers of this EIR have therefore conducted a screening-level analysis of the potential to exercise market power with various combinations of the Pacific Gas and Electric Company hydropower assets and thermal generating capacity participating in California electricity markets.[39] This section describes the rationale, methods, and results from this screening-level Market Power Analysis.

6.3.1 Study Approach and Scope

Department of Justice guidelines characterize market power to a seller (such as an electric generator) as "…the ability <u>*profitably*</u> to maintain prices above competitive levels for a significant period of time"[40] (emphasis added). This analysis has considered three ways in which market power in conjunction with ownership of hydro facilities might be exercised in California power markets.

- First, the owner could shift certain hydro facilities' generation away from the peak load (high market price) hours, generating less in these hours than would be optimal (most profitable) under fully competitive conditions. This would be profitable if it increased market prices enough so that net

37 I. 00-08-002.

38 Settlement Agreement for Valuation and Disposition of Hydroelectric Assets, Appendix D, "The ISO-PG&E Corporation Market Power Mitigation Agreement."

39 As discussed in Section 3.2.4, this scenario would not be limited solely to ownership by PG&E Corporation affiliates. Other current owners of thermal generation that could fall into this category include Southern Energy, Duke Energy, and Calpine.

40 U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, Issued April 2, 1992 and revised April 8, 1997.

income increases for the owner's other generating facilities outweighed the net income losses for the shifted hydro generation.

- Second, the owner could withhold generation at some of its non-hydro facilities, particularly gas-fired thermal power plants in California. In the time periods affected, these facilities would then generate less than would be optimal (most profitable) under fully competitive conditions. Again, this would be profitable if it increased market prices enough so that net income increases for the owner's other facilities (including hydro) outweighed the losses for the withheld generation.

- Third, hydro capacity might be withheld from participation in ancillary services (AS) markets, driving up prices in both A/S and energy markets.

While the exercise of market power is generally considered to entail the ability to profitably raise market prices for a *significant* period of time, the relevant market may itself be discontinuous in time. This is especially true for electric generation, because demand and also other relevant circumstances such as availability of generation, fuel and transmission can vary considerably over seasons, days, and hours, while electricity cannot be readily stored and must be generated to meet current requirements. This means that the circumstances of supply and demand vary greatly over time, but with similar circumstances repeating themselves in both unpredictable and predictable (such as seasonal, and daily) ways. Because of this, investigating whether there is significant potential for exercising generation market power in conjunction with hydro facility ownership requires considering a wide and complex range of interacting factors such as:

- electric loads;
- hydrologic conditions;
- ownership of hydro and other generating facilities; and
- the amount of competing (under different ownership) generation that is available in those time periods and conditions for which there is reason to believe that market power might be exercised.

All of the above factors have been considered in the market power analysis presented here. However, because the analysis was brief, the breadth of factor combinations analyzed was limited. The different factors considered are outlined below.

Loads

A single load forecast has been considered for California and the WSCC, for the modeling period consisting of calendar year 2005. However, since this forecast involves 8,760 individual hourly loads at each load center, it actually represents a range of load conditions.

Hydrological Conditions

Four separate yearly sets of hydrologic conditions have been considered, based on historic water conditions in "hydro years" 1976 (dry), 1977 (critically dry), 1979 (average), and 1998 (wet). The different hydrologic conditions reflect very different amounts of water being available for electric generation over the course of a year at the Pacific Gas and Electric Company hydro facilities, over the rest of California, and across the overall WSCC. This affects power markets and potential for exercising market power in California. Figure C-33 indicates how these years stand in relationship to other historical hydro years between 1975 and 1998, in terms of hydroelectric generation in California and across the WSCC. Note that a wet or dry year in northern California is usually, but not always, a wet or dry year for the WSCC overall. In addition, within each hydro year, water availability for hydro generation varied seasonally, creating a still greater diversity of conditions

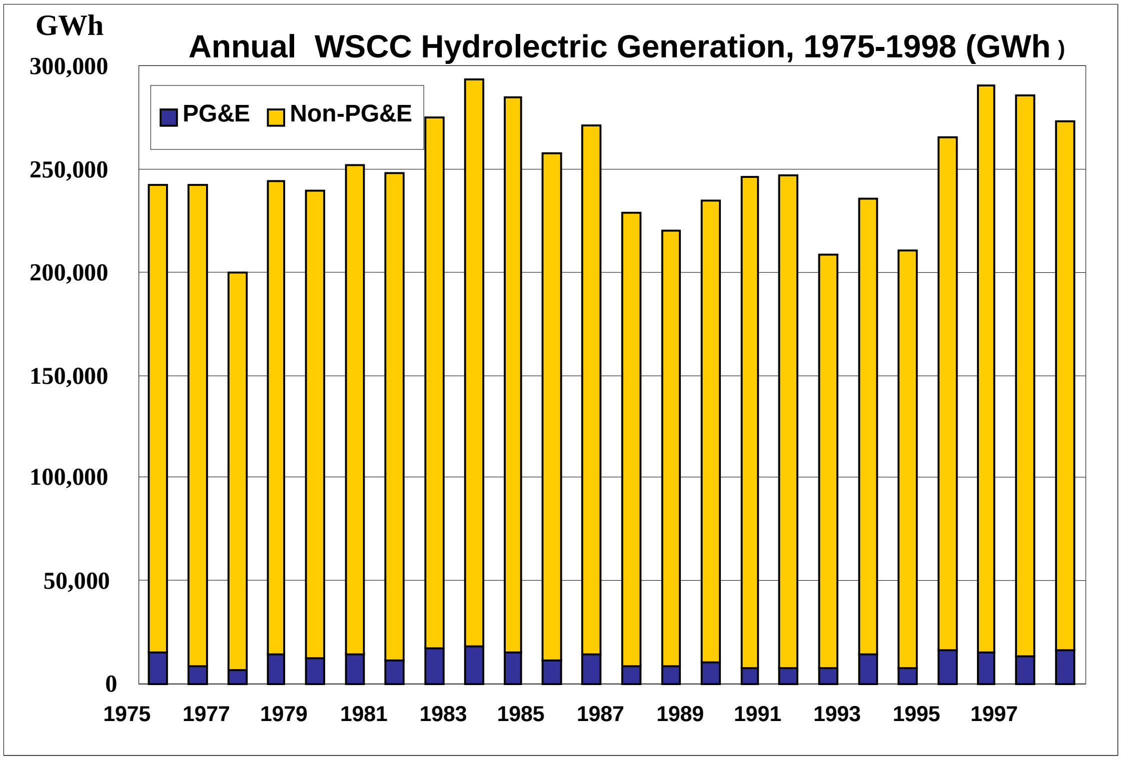


Figure C-33. Annual Hydroelectric Generation: Pacific Gas and Electric Company vs. WSCC Overall

affecting hydroelectric generation and power markets. Of these four hydro years, 1979 (average conditions) was analyzed most extensively. Hydro year 1998 was selected because it was among the wettest in the 24-year hydrology, and those hydrologic conditions appear to have been included in the recent analysis of market power potential associated with Pacific Gas and Electric Company hydro facilities.[41]

41 By analyzing 1998 hydro year conditions, the results presented here can be compared with the ORA analysis by Laurence Kirsch in ORA Testimony, Chapter VI-Market Power Implications Of Hydro Power Divestiture (March 2000), who relied upon a different methodology that was also used in James Bushnell, "Water and Power: Hydroelectric Resources in the Era of Competition in the Western U.S.," (PWP-056r, Program on Workable Energy Regulation (POWER), University of California Energy Institute, Berkeley, CA, July 1998) and Severin Borenstein, James Bushnell, and Frank Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," (PWP-064, Program on Workable Energy Regulation (POWER), University of California Energy Institute, Berkeley, CA, March 20) to analyze market power issues in the WSCC.

Ownership

Six separate groups ("portfolios") of Pacific Gas and Electric Company hydroelectric facilities have been considered when analyzing the effects of shifting output from hydroelectric or thermal facilities to increase net income for the owners' overall portfolio of generating assets. The six hydro portfolios are identified in Table C-17. Helms and the other Kings River powerhouses are not included among the portfolios considered in this analysis.[42] Potential alterations of output patterns for a large pumped storage facility such as Helms are complex and in many ways differ from those associated with shifting output at storage hydro facilities. For example, the amount and not just timing of output may be adjusted substantially, and it is nontrivial to establish what constitutes "normal" operation of pumped storage facilities in newly competitive markets.

Table C-17
Basin-Specific Groups of Hydroelectric Plants Considered to Be Owned and Operated as Part of Asset Portfolios

	MW Capacity		MW Assumed Able to be Scheduled (Shifted On- or Off-Peak)	
Group	Total MW in Portfolio	Share of PG&E Total	Total MW in Portfolio	Share of PG&E Total Hydro MW Assumed Able to be Scheduled
1. North Fork Feather River (NFFR)	734	18.8%	728	20.6%
2. NFFR plus McCloud-Pit	1502	38.6%	1417	40.2%
3. Group 2 plus Crane-Kerckhoff	1724	44.2%	1592	45.1%
4. Group 3 plus Mokelumne	1939	49.8%	1748	49.6%
5. Group 4 plus South Yuba (Drum)	2141	55.0%	1874	53.1%
6. Group 5 plus Stanislaus	2241	57.5%	1965	55.7%

This analysis also considered generic and specific amounts of thermal generating capacity that might hypothetically be part of combined thermal-hydro generating portfolios. Such portfolios are used to examine if market power might be exercised under various conditions. Clearly, any actual opportunities for exercising market power would depend on what specific combinations of hydro and thermal plant ownership develop, which is presently speculative.

42 Kirsch's analysis found that control of Helms and the Kings River system played a significant role in the ability to manipulate market prices. The analysis presented here does not review the exercise of market power through the Helms pumped storage facility.

Other Generation

The amount of other generation competing in northern California power markets has a major impact on the potential for exercising market power via owning hydroelectric facilities plus thermal plants. A higher level of generator market entry by the simulation time horizon of 2005 generally reduces the potential for exercising market power, because greater availability of moderately priced generation can reduce market price increases achievable through withholding generation. This analysis considered two different levels of generation market entry in California out to 2005. Assuming proposed projects come on line as announced produces the "Proposed" market entry scenario, resulting in projected in-state generating capacity increasing by just over 11,000 MW between 2000 and 2005, with virtually all additions being gas-fired. The "Proposed" market entry scenario for 2005 was used for modeling all cases (except the "Moderate" market scenario described below) in the Draft Environmental Impact Report (EIR).[43] Assuming delays in bringing proposed projects on line, the "Moderate" market entry scenario results in generator additions that increase total generating capacity in California by about 5600 MW between 2000 and 2005, with about 97% of the added capacity being gas-fired (Table C-18 & C-18a).

Table C-18
Projected California In-State Generating Capacity
With Two Market Entry Scenarios for 2005

Fuel Type	Year 2000		2005 "Moderate"		2005 "Proposed"	
	Amount (MW)	Share	Amount (MW)	Share	Amount (MW)	Share
Geothermal	2364	4.9%	2510	4.7%	2510	4.2%
Gas	25660	53.3%	31114	57.9%	36682	61.9%
Nuclear	4310	9.0%	4310	8.0%	4310	7.3%
Oil	750	1.6%	750	1.4%	750	1.3%
Other	3380	7.0%	3380	6.3%	3380	5.7%
P. Storage.	3108	6.5%	3108	5.8%	3108	5.2%
Hydro	8540	17.8%	8540	15.9%	8540	14.4%
Total	48112	100%	53712	100%	59280	100%

Due to transmission constraints and costs, it is generating capacity in California that has the greatest bearing on northern California power markets and the potential exercise of market power, especially during peak load conditions. However, WSCC generation from outside of California also plays a significant role in California power markets. Modeling for this analysis includes a forecast increase in WSCC generating capacity outside of California between 2000 and 2005 that amounts to almost 8,000 MW. This has some impact on the potential for exercising market power in northern California power markets, and if a lesser amount of WSCC capacity additions should materialize, the potential for market power in northern California might be higher. As with the

43 To the extent that new generation is proposed by existing generators, their potential ability to exercise market power could be enhanced by delaying the completion of such new generation.

forecasted California additions, the modeling analyses of the other cases assumes entry of the entire portfolio of proposed new generation.

All of these factors (loads, hydrologic conditions, ownership, other generation and market entry) played a role in the analysis. Certain circumstances have been identified under which there may be potential for exercising market power associated with ownership of hydroelectric generating facilities in California. By clarifying how certain combinations of conditions produce elevated potential for market power, we can ultimately focus on the dynamics underlying the most relevant conditions, and can evaluate the frequency with which such conditions might occur. For there to be significant potential for market power, the right conditions would have to occur frequently enough, and to be sufficiently predictable by would-be practitioners of market power. Nevertheless, this analysis is intended only to assess the potential for exercising market power, rather than the likelihood of such exercise.

Table C-18a
New California Power Plants Included in Modeling Analysis Forecasts for 2005

Plant Name	Company	Size	Fuel Type	2005 Scenario Primary Cases MPA "Proposed"	2005 Scenario MPA "Moderate"
Los Medanos	Calpine	500	Gas	X	X
Salton Sea	Cal Energy	49	Geo	X	X
Las Palomas	PG&E NEG	1,048	Gas	X	X
Sutter	Calpine	500	Gas	X	X
Chula Vista	Duke	49	Gas	X	X
Telephone Flat	Cal Energy	48	Geo	X	X
Delta Energy Center	Calpine	880	Gas	X	X
Fourmile Hill	Calpine	49	Geo	X	X
Sunrise	Texaco	320	Gas	X	X
ElkHills	Sempra	500	Gas	X	X
Otay Mesa	PG&E NEG	510	Gas	X	X
Mountain View 1	Thermo-Ecotek	528	Gas	X	X
High Desert	Inland	680	Gas	X	X
Nueva Azela	Sunlaw	550	Gas	X	
Three Mountain	Ogden Power	500	Gas	X	
Metcalf Energy Center	Calpine	600	Gas	X	
Blythe	Summit	520	Gas	X	
Midway 2	ARCO	500	Gas	X	
Contra Costa	Southern	530	Gas	X	
Moss Landing	Duke	1,090	Gas	X	
Pastoria	Pastiori	750	Gas	X	
Mountain View 2	Thermo-Ecotek	528	Gas	X	
Total Capacity (MW)				11,229	5,661

The analysis has focused on short-term variations in hydroelectric and thermal unit operations that might constitute exercise of market power, through reducing output and increasing net income, compared to what would be expected under fully competitive conditions.[44] By "short term," we mean alteration of the pattern or amount of generator output across the hours within an individual month. It could be expected that over such a short time horizon, owners would have considerable ability to anticipate key drivers of market prices, such as water conditions, generator availability (including outages), fuel prices, and, to a lesser extent, loads. Such anticipation would increase the likelihood that conditions favorable to exercise of market power might actually be foreseen and exploited. This analysis implicitly assumes that the owners in question do in fact anticipate these short-term (within-month) conditions. Reduced ability to anticipate these conditions would mean less potential for exercise of market power.

This analysis has considered two ways of altering hydro output to raise market prices and potentially increase net income for an overall generation portfolio, and two ways of withholding thermal generation to achieve the same result. These screening-level analyses help to identify the conditions under which it could be profitable to exercise market power. The two ways of altering hydro output that were investigated are

- A "baseload" strategy shifts output from storage hydro facilities (whose output in any month is limited, but can be timed) away from the typical, competitive "peaking" strategy of concentrating output in peak (high load, high price) hours. Instead, the output is the same in every hour of a month (but still varying month to month due to changing water supply).

- "Inverting", under which generation at storage hydro facilities is shifted even further away from the peaking pattern, so that output is higher in off-peak hours than in peak hours.

These two strategies were simulated for each of the six progressively larger groups or "portfolios" of Pacific Gas and Electric Company hydro facilities identified in Table C-17. Such generation shifting is only possible for "storage hydro" plants with sufficient water storage that they can time their output, at least over the course of a day. The amount of hydroelectric generating capacity having this timing flexibility, and thus being simulated to shift output, is shown for each of the six portfolios in Table C-17.

For thermal units, two kinds of generation withholding behavior were analyzed:

- Entire generating units were assumed to be made unavailable (effectively, placed on outage) over an entire month. While an entire calendar year was simulated, each of 12 months was evaluated as a separate time interval over which generation might be withheld in this manner, to evaluate the potential for profiting from such withholding of output under different conditions.

- A selected cycling thermal generator having some impact on projected market prices was assumed to withhold part of its output in various hours of the month, and the effect on market prices and net income for overall hydro-thermal portfolios was analyzed.

---

44 A key assumption is that the baseline, competitive situation being simulated (in this case the PowerMax Case from the CEQA study) does in fact represent optimal competitive behavior in the absence of market power, so that any deviation producing significantly greater income with less generation, over a significant period of time, does in fact represent exercise of market power.

6.3.2 Results: Shifting Hydro Generation

WSCC power markets were simulated over the 12 months of projected year 2005, under several different sets of hydrologic conditions. Two different strategies for shifting hydro generation strategies were simulated as described earlier, the "baseload" and "inverted" strategies. This resulted in changes in projected peak and off-peak market clearing prices (MCP) for electric energy in the northern California pricing zone, compared to the baseline prices projected under the PowerMax Case.

The PowerMax Case optimally allocated each powerhouse's generation over the months of a year and then over the different hours of a month, assuming fully competitive conditions and treating each powerhouse as separate profit center and not as part of a portfolio that could potentially exercise market power. Only "hard" (binding) water use constraints were assumed, giving somewhat greater flexibility of water use and generation timing than would be available under additional, informal (nonbinding) water use agreements currently being observed. Starting from the PowerMax Case, "baseload" and "inverted" generation shifting were simulated for each of the six hydro portfolios listed in Table C-17, for the combinations of conditions shown in Table C-19.

Table C-19
Combinations of Conditions for Which Hydro Strategies "Baseload" and "Inversion" Were Analyzed

Water Conditions (Hydro Year)	Market Entry by 2005 (M, P = Moderate, Proposed)	Strategy Analyzed for Each Month (B, I = baseload, inverted)
1976 (dry)	M, P	B, I
1977 (critically dry)	M, P	B, I
1979 (average)	M, P	B, I
1998 (wet)	M, P	B

Based on the resulting increase in on-peak MCP, the "breakeven" amount of thermal capacity that the owner would have to own was calculated and plotted. This is the amount of thermal capacity that, if running during all peak hours of a given month, would experience a net income increase (relative to the PowerMax Case) that would exactly offset the income decrease for the hydro part of the portfolio due to generation shifting. Thus the hypothetical hydro-thermal portfolio would break even. Owning additional thermal capacity would result in an income increase, relative to the PowerMax Case.[45]

Since the objective of shifting hydro generation is to increase MCP during peak hours, it would make sense to own thermal generation running during peak hours, since hydro generation is

[45] For this analysis the "peak hours" run from 6 AM to 10 PM seven days a week, compared to only five days a week as used to graph duration curves for hourly hydro generation and market prices (MCP) in the presentations on the primary cases above.

actually *increased* in off-peak hours (which should generally lower off-peak prices). Gas-fired thermal units in California would be most likely to run in peak, as opposed to off-peak, hours.

Shifting hydro generation away from peak hours reduces projected income for hydro facilities whose generation is shifted. This is only partly offset by income increases at other, run-of-river (non-storage) hydro facilities in the same portfolio, due to their limited generation. However, if the owner also owns other capacity that is running during peak hours, such as thermal units, then income from the overall portfolio are projected to increase under some of the conditions that were analyzed.

Table C-20 illustrates how applying this "baseload" shifting strategy for a hydro portfolio assumed to consist (only) of Pacific Gas and Electric Company's North Fork Feather River system of powerhouses (734 MW) has the following consequences when simulated for summer months under hydro year 1979 (average) water conditions.

- The hydro portfolio alone experiences operating losses since it generates less during peak hours with high market prices (while generating more during off-peak hours).
- The resulting increase in the peak MCP varies among the four months. This reflects a diversity of supply/demand conditions that would be even greater if considering more months, more hydro years, or individual hours.
- For three of the four months, most notably August, the "baseload" strategy drives up peak MCP substantially more under "Moderate" market entry than under "Proposed" market entry. This likely reflects the much tighter supply situation under lower market entry, especially during summer peak hours.
- The amount of thermal (or other) generating capacity that an owner would have to have running on-peak to offset hydro losses varies considerably among months (and hours within a month). This reflects the way that MCP responds much more to hydro shifting in some months (and in some hours) than others. Among only four months and two market entry scenarios displayed in Table C-20, the amount of thermal (or other) capacity the hydro owner would need to have running in all peak hours of the month in order to offset the hydro income losses ranges from under 600 MW to over 40,000 MW. If considering individual hours, the variation would be even greater.

Table C-20
Effect of the "Baseload" Hydro Strategy for a Portfolio Assumed to Include Feather River Hydro Plus Thermal Generating Capacity
Hydro year 1979, Summer Months

Month	Proposed Market Entry by 2005			Moderate Market Entry by 2005		
	Income Loss, Hydro ($1000)	Increase in Peak MCP, $/MWh	Thermal MW Needed to Break Even	Income Loss, Hydro ($1000)	Increase in Peak MCP, $/MWh	Thermal MW Needed to Break Even
June	916	0.48	3976	987	0.13	15817
July	2583	0.36	14466	2864	0.85	6793
August	2563	0.57	9066	2538	9.09	563
Sept.	2418	0.11	45795	2226	0.32	14492

This specific example represents one of several situations in these simulations where this sort of simplistic exercise of market power could plausibly succeed. By considering more sophisticated strategies for altering hydro output focused on narrower sets of hours and circumstances, the potential rewards could be increased. However, in the real world it would always be necessary for the would-be practitioner of market power not only to own the appropriate portfolio of assets but also to anticipate the occurrence of favorable conditions with sufficient accuracy. For this reason, these results must be viewed in the context of being plausible, but not necessarily likely, situations when market power could be exercised effectively. Nevertheless, these plausible situations do include likely ones as a subset.

The "breakeven" amount of thermal capacity that the owner would have to own was calculated and plotted for a variety of circumstances. This is the amount of thermal capacity that, if running during all peak hours of a month, would experience an income increase (relative to the PowerMax case) sufficient to exactly offset the income decrease for the hydro part of the portfolio due to generation shifting. Thus, the hypothetical hydro-thermal portfolio would break even. Owning additional thermal capacity would result in an income increase, relative to the PowerMax case.

Table C-21 summarizes results from simulating the "baseload" shifting strategy under different water conditions (hydro years) and market entry scenarios, for different hypothetical hydro portfolios. This table identifies those months (entire months, not individual hours) for which the strategy was found to pay off after thermal capacity ownership exceeded levels that could realistically be attained. This occurred most frequently in summer months when projected MCP are high, supply is tight, and shifting hydro generation away from peak hours can produce substantial increases in the MCP. However it also occurred in some winter/spring months. As discussed below, a key driver is the shape of the generation supply curve, affecting how much the marginal bid (and the MCP) rise for a particular change in supply. This varies by hour, season, and in response to many factors such as hydrologic conditions and market entry.

The simulated consequences of the "inverted" strategy were similar to those for the "baseload" strategy. While the "inverted" strategy can shift more hydro generation away from peak hours, this is limited by the fact that only so much hydro generation from powerhouses can be moved into the off-peak hours, and also by the fact that any hydro generation remaining in the peak hours can benefit from the increased peak MCP.

Some of the results summarized in Table C-21 are depicted in Figures C-35 to C-37. Four key observations are as follows.

- Even on a month-long basis (not targeting selected hours), the "baseload" strategy can be successful in certain conditions, especially in the summer (see Figures C-35, C-36, and C-37), but also potentially also in other seasons (Figure C-37).

- The financial consequences of such a strategy vary considerably across months, hydro conditions, market entry conditions, and the amount of assumed hydro ownership. This suggests the need to better understand the fundamental drivers of the potential for market power. It also suggests that in the real world it might be challenging to anticipate the occurrence and duration of conditions conducive to exercising market power.

- Under a particular combination of conditions, a smaller hydro portfolio (Feather only) sometimes required the smallest amount of thermal capacity in order for hydro shifting to succeed. However, under some conditions it was the largest hydro portfolio analyzed that performed best, and sometimes it was an intermediate portfolio. This again hints at the complexity of the underlying conditions influencing the potential for exercising market power. However, which hydro portfolio was considered was generally much less important than the how various other factors combined and interacted, making the MCP more or less sensitive to hydro shifting.

- Although not directly tested, hydro shifting might succeed even without thermal ownership, if the peak MCP could be increased sufficiently, and if the owner had enough other hydro generation (within or outside of the 6 portfolios considered here) still running in peak hours and thus benefiting. Simulated mid-summer conditions under Moderate market entry and 1979 hydro conditions suggest such a possibility (Figure C-34 and Table C-21).

Table C-21 Conditions Under Which Ownership of Realistic Amounts of Thermal Capacity Made Month-Long "Baseload" Hydro Shifting Pay Off			
Hydro Year and Market Entry Scenario	Hydro Portfolio (1)	Months in which the "Breakeven" On-Peak Thermal Capacity is in the Following MW Ranges	
		<1500 MW	<4000 MW
1976, Proposed	1		May
	2		March, May
	4		January, March, May
	6		March, May
1976, Moderate	1		
	2		
	4		
	6		
1977, Proposed	1		
	2		
	4	August	August
	6	August	August
1977, Moderate	1		July, August
	2		July, August
	4		July, August
	6		July, August
1979, Proposed	1		March
	2		March
	4		March, April
	6		March, April
1979, Moderate	1	August	May, August
	2	August	May, August
	4	August	May, August
	6	August	May, August
1998, Proposed	1		
	2		
	4		April
	6		April
1998, Moderate	1		June
	2		June
	4		June
	6		June

(1) Hydro portfolios: 1 = Feather, 2 = Feather+Pit, 4 = #2 plus Crane/Kerckhoff and Mokelumne, 6 = #4 plus S. Yuba and Stanislaus. (Portfolios 3 and 5 produced intermediate results.)

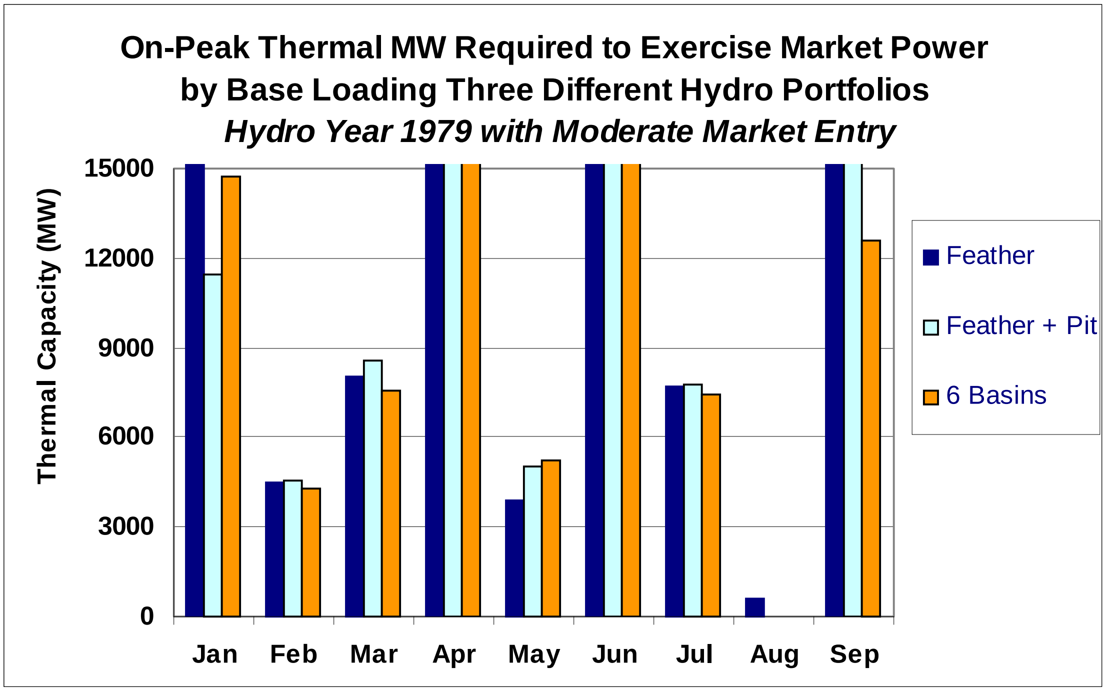


Figure C-34. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1979 (average) with "Moderate" market entry***

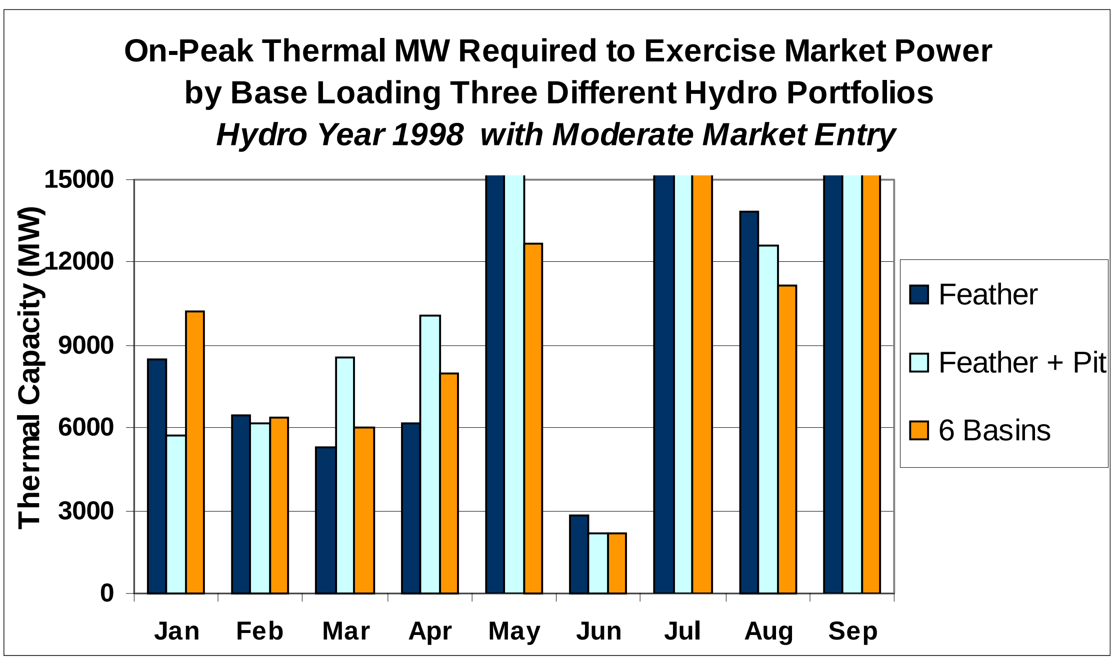


Figure C-35. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1998 (wet) with "Moderate" market entry***

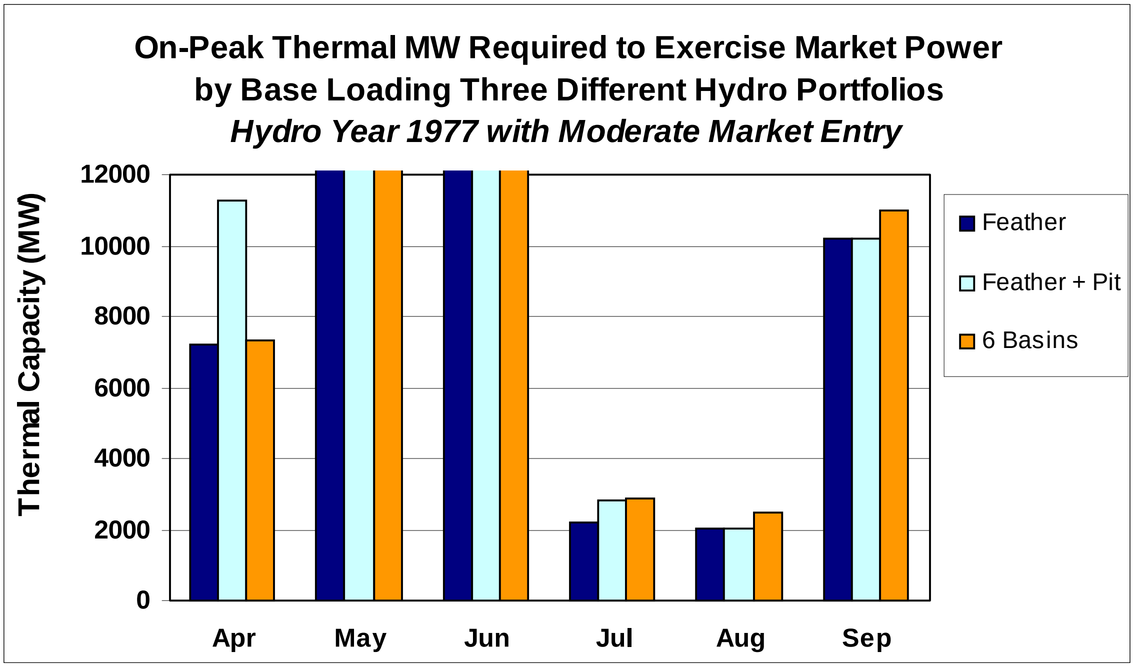


Figure C-36. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1977 (critically dry) with "Moderate" market entry***

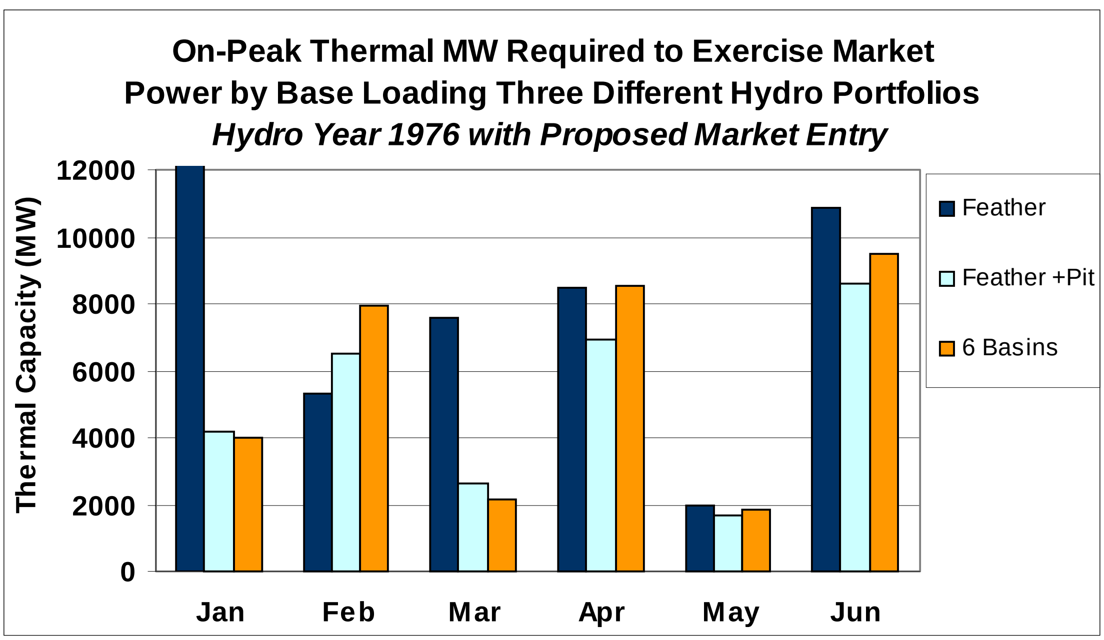


Figure C-37. On-Peak Thermal MW Needed to Break Even When Shifting Hydro: ***Hydro Year 1976 (dry) with "Proposed" market entry***

Changes in market prices due to shifting hydro generation not only affect producer revenues and income, they also affect consumers' payments. We have developed a preliminary, illustrative estimate of the increase in electric energy costs for the combined customers of Pacific Gas and Electric Company, SCE, and SDG&E when moving from the original PowerMax Case to the "baseload" hydro shifting strategy simulated for Hydro Portfolio 2 (Feather and Pit systems). The estimate was made for the month of August 2005 with 1979 hydro conditions and Moderate market entry, circumstances previously depicted in Table C-20 and Figure C-34.

The additional cost to consumers was estimated under three different PX price cap levels, assuming no elasticity of electricity demand within this price range (Table C-22). The price increases (and some off-peak price decreases) over the month combine with the projected customer loads (Figure C-38) to produce the overall estimated increase in consumer costs for electric energy. The actual simulation such as depicted in Figures C-35 to C-39 assumed the $750 price cap.

Table C-22
Additional Pacific Gas and Electric Company, SCE and SDG&E Customer Payments for Electric Energy Due to Simulated Hydro Shifting (Base Loading) in the Month of August
Feather + Pit shifted, 1979 hydro conditions, Moderate market entry

Cap $/MWh	Additional Payment $Million
750	287.24
500	182.4
250	77.5

As previously suggested, an interaction of factors determines when and how hydro generation shifting has the potential to drive up MCP sufficiently to produce potential for exercising market power. We gain further insight into how this occurs by considering the hourly patterns of both hydro generation and MCP. Storage hydro whose output can be timed is generally expected to cycle its output, to high levels during high load (high market price) hours of the day and week, and down to low or minimum (minimum water passage) levels during off peak hours. This is illustrated for the "PowerMax" case in Figure C-38. Such clear cycling is especially likely during the summer, when loads, market prices and the value of water (for generation) are all highest. In contrast, the "baseload" strategy assumes that storage hydro facilities produce the same MW level of output in each hour of a month (Figure C-39). Since the MCP is substantially higher during the peak hours (Figure C-40), the cycling output pattern produces higher expected hydro generation income, under the original the PowerMax Case.

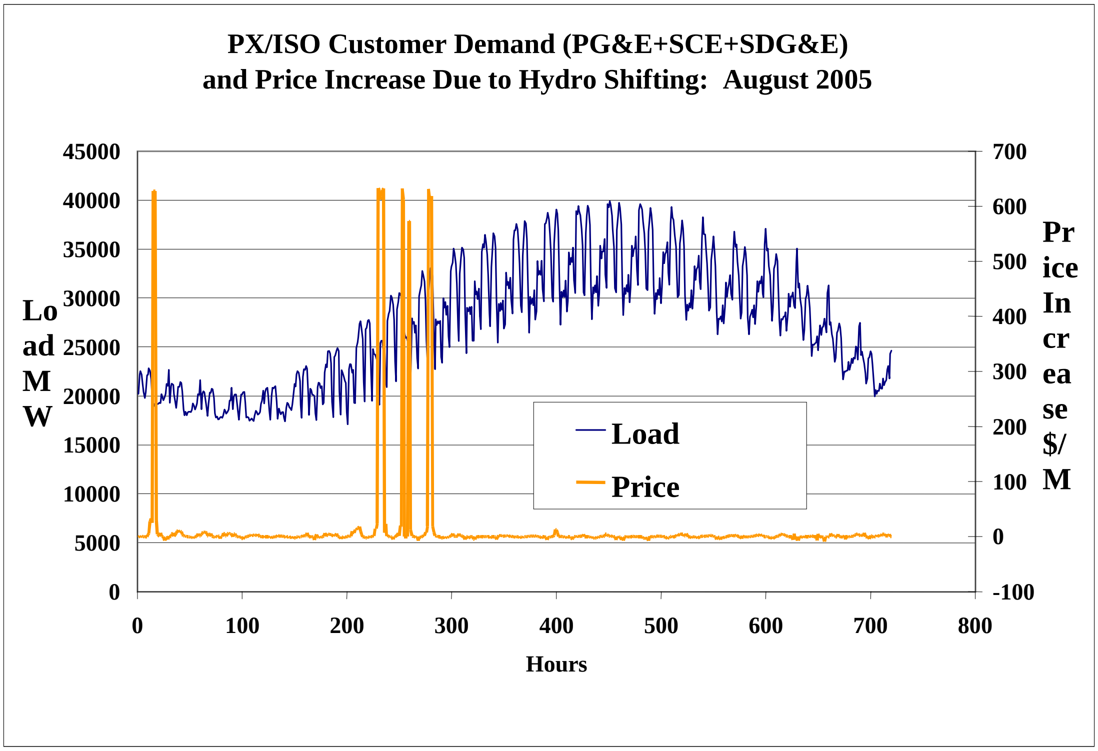


Figure C-38. Hydro Shifting: Customer Loads and Price Increases Translate into Increased Consumer Cost for Electric Energy

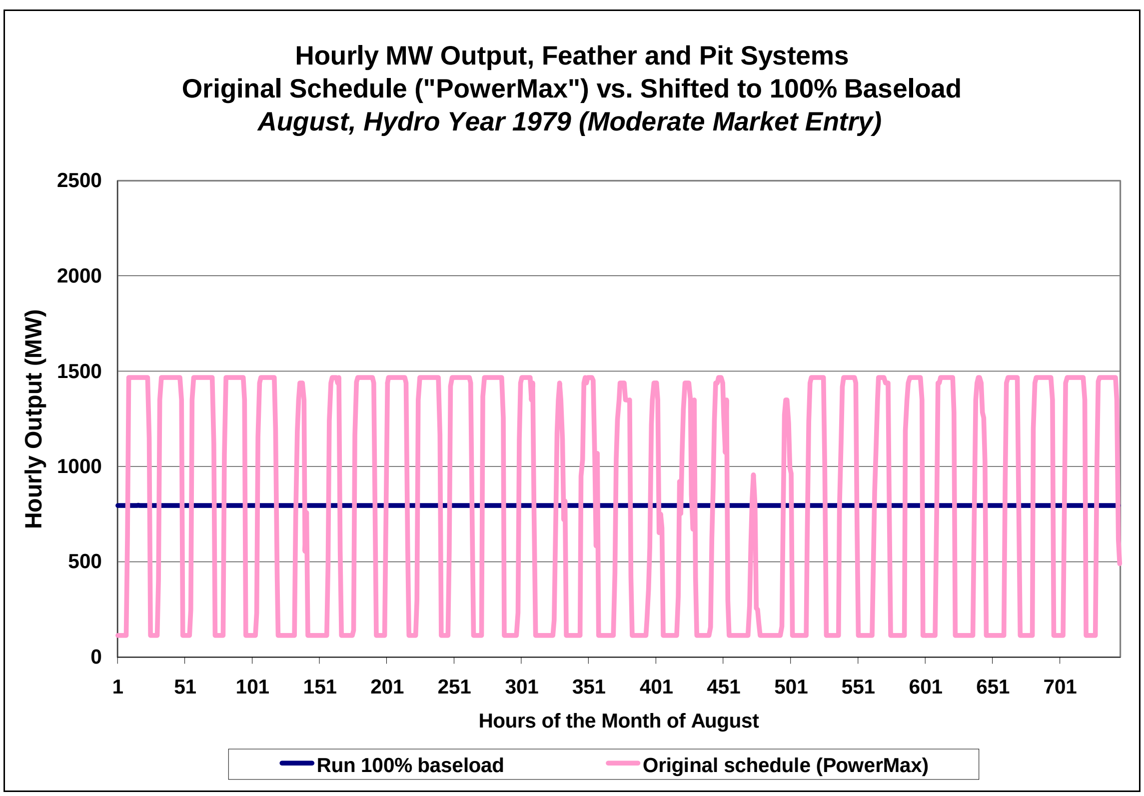


Figure C-39. "Baseload" Strategy Shifts Hydro Output from Cycling to Flat

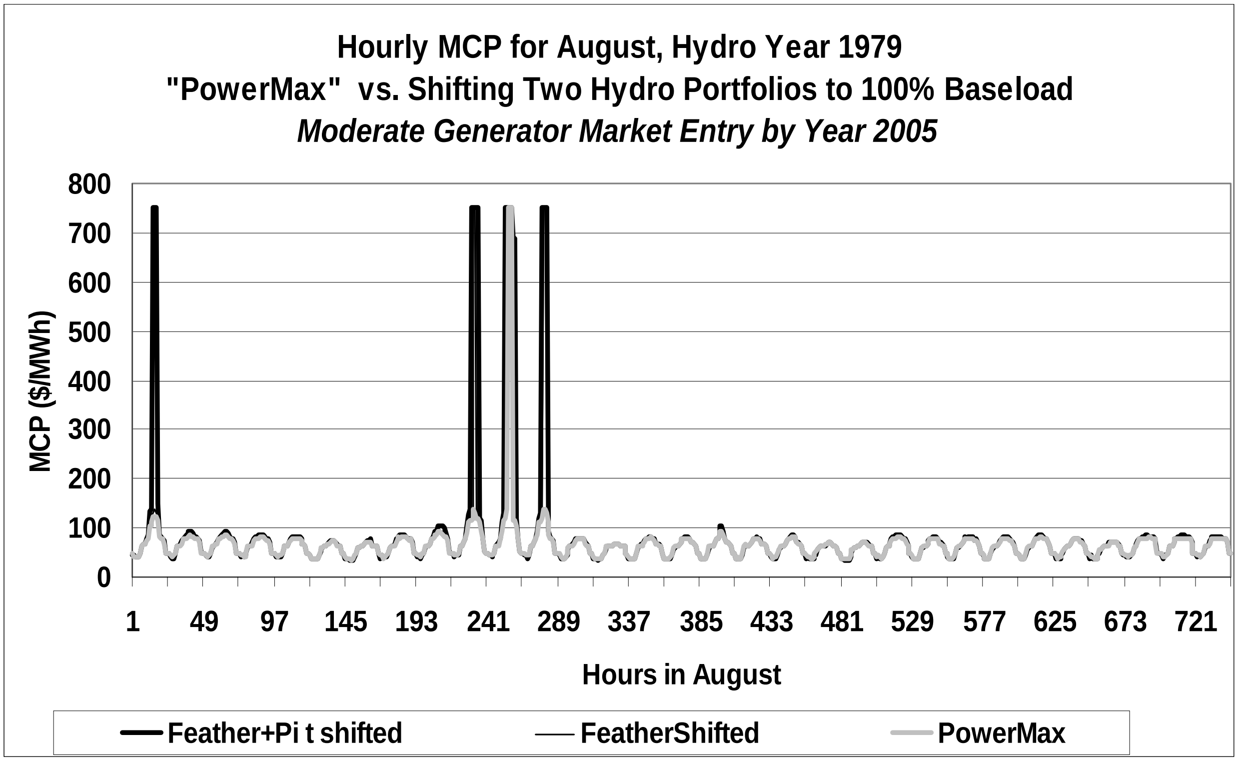


Figure C-40. In the Summer, Projected MCP Cycles Daily, Occasionally Spiking

Under the original competitive conditions (the PowerMax Case) MCP is projected to cycle not only daily during August, but on one day to spike at very high levels, reaching the mandatory cap. This reflects the combined effect of the underlying drivers, such as projected loads, the availability of water for hydro generation, and the availability of generators and transmission, in a relatively tight overall generation supply situation. Such price spikes represent an important revenue source for generators. Under the "baseload" strategy with hydro generation shifted away from peak hours, the peak MCPs are slightly elevated on many days. Further, the duration of the original price spike is increased and there are three additional days with price spikes. This can be seen in Figure 40, but more clearly in Figure C-41 that focuses on a single week. Such elevation of the MCP explains why under this particular set of conditions the "baseload" hydro shifting strategy was simulated to be successful when combined with ownership of only a small amount of thermal capacity.[46]

46 This strategy would be effective with an even smaller amount of thermal capacity if the hydro owner could reliably focus the release-shifting strategy to the days when generation resources are more scare and price spikes more likely, rather than for the entire month as shown here.

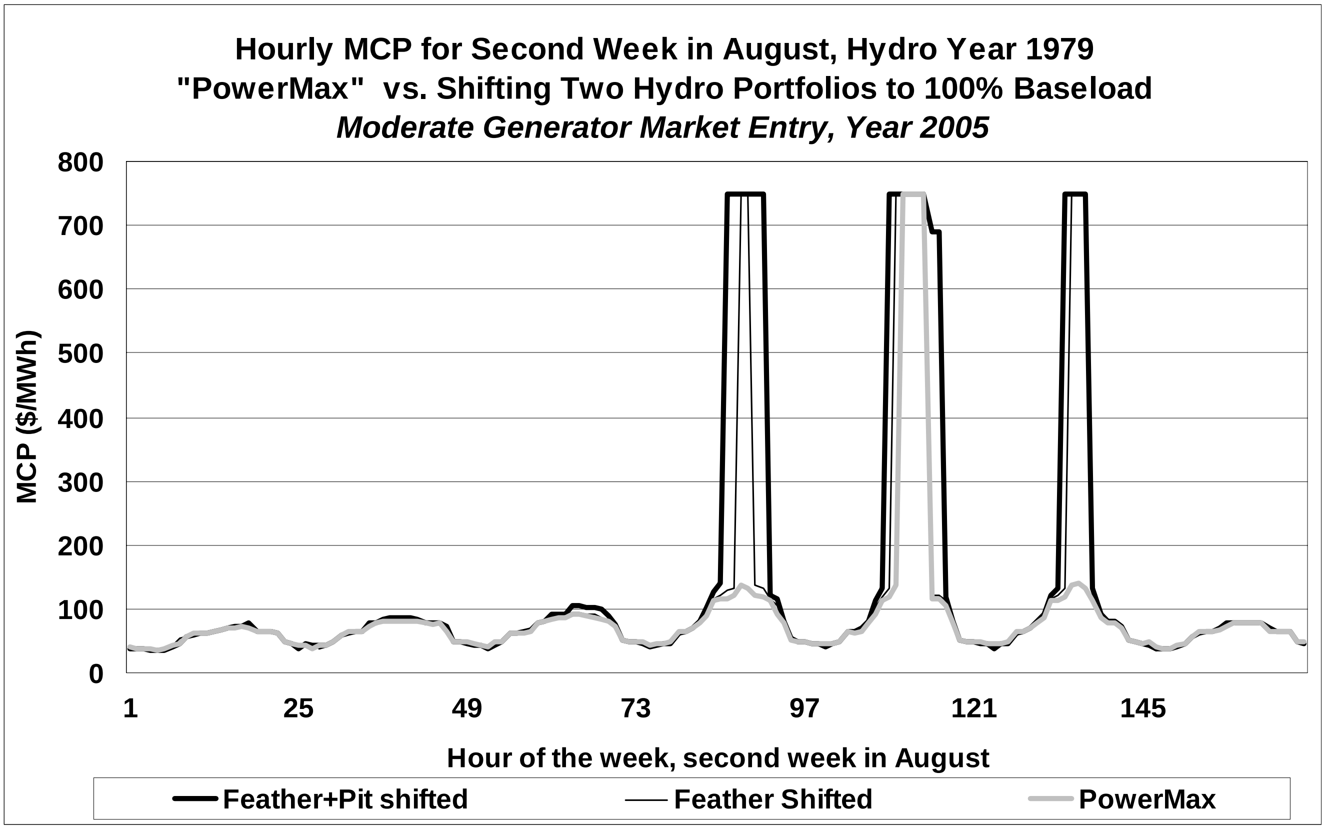


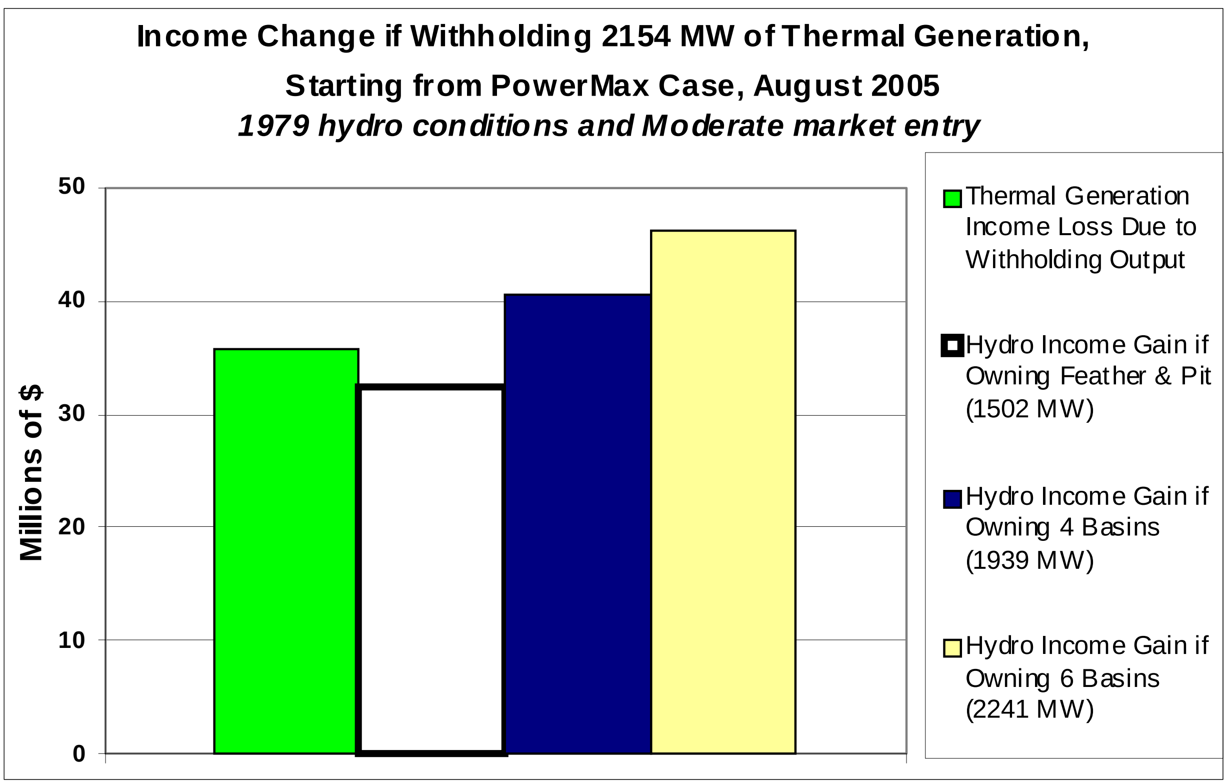
Figure C-41. Shifting Hydro Generation: More (and Longer) Projected Price Spikes

6.3.3 Results: Withholding Thermal Generation

The second general kind of market power strategy analyzed is withholding of thermal generation to increase the MCP. This could pay off if the owner has sufficient generation still in the market, including hydro, to benefit from the increased MCP. The strategy pays off if this remaining generation obtains an income increase outweighing the loss due to withholding generation. A wide range of amounts and types of thermal capacity could be considered as candidates for such generation withholding, over a wide range of time periods and conditions. Gas-fired cycling units that run mostly during peak and shoulder peak hours at narrow profit margins may be the best candidates. This analysis simulated the impact of a substantial amount of gas-fired capacity being held off-line for an entire month at a time. This test helps to identify conditions under which a withholding strategy is especially promising. In practice, withholding strategies would likely be more refined to increase chances for success, such as by focusing on a narrower set of hours or withholding only portions of a plant's output. In this screening test, the actual units simulated to act in this fashion were Moss Landing 6 and 7 and Morro Bay 3 and 4, all owned by Duke Energy, totaling about 2,200 MW.[47] This behavior was simulated for five sets of hydro conditions, as follows:

- hydro year 1977 (critically dry) under "proposed" market entry,
- hydro year 1979 (average) under both "proposed" and "moderate" market entry, and
- hydro year 1998 (wet) under "proposed" and "moderate" market entry

As illustrated in Figure C-42, when combined with ownership of certain hydro portfolios (Feather + Pit or larger), this thermal withholding was simulated to "pay off" in August 2005, under hydro year 1979 conditions and Moderate market entry. Among the other months in which the projected capacity factor for these four thermal units combined reached at least the 10% range, a positive payoff was simulated for two of the months. As summarized in Table C-23, the hypothetical strategy illustrated in Figure C-42 would not quite pay off if the overall generation portfolio included the four thermal units plus the Feather and Pit systems, but would pay off if additional hydro capacity was added to the portfolio. For the month in question, the amount of generation from the Feather and Pit systems is about 60% of the amount of withheld thermal generation. It is likely to be generation from storage hydro that benefits most from withholding thermal generation,



---

47 These units were selected because they represent a large amount of existing gas-fired capacity under common ownership in northern California. Their selection is for illustrative purposes and is not intended to suggest that Duke Energy is more or less likely to attempt to exercise market power than are any other owners of generation participating in California power markets.

since storage hydro generation would be concentrated in peak hours, unlike run-of-river hydro generation.

Figure C-42. Owning Enough Hydro Can Make Withholding Thermal Generation Pay Off

Table C-23
Elements Contributing to Overall Benefits of Withholding Thermal Generation in the Previous Example

Change in Income if Withholding Generation from Selected Thermal Units While Also Owning Different Hydro Systems
August, Hydro Year 1979 - - "Moderate" market entry

Assets	Income change, $1000
Morro Bay 3	-5374
Morro Bay 4	-5648
Moss Landing 6	-15104
Moss Landing 7	-9629
Feather	16173
Pit	16171
Mokelumne	4262
Crane/Kerckhoff	3987
South Yuba	3652
Stanislaus	2134
NET TOTAL	**10624**

A second, more focused thermal generation withholding strategy was also analyzed. Under the Moderate market entry scenario with 1998 (wet) hydro conditions, a gas-fired, cycling generator in northern California was assumed to decrease its output by 30 MW in selected hours during the first week in August, 2005. The actual unit selected was part of Southern Energy Company's approximately 3,000 MW thermal generation portfolio in northern California.[48] This 30 MW of generation represents about one percent of the owner's overall generation portfolio in northern California. If not withheld it would have been profitable, generating at a marginal cost below the MCP for the hours in question. The result of withholding was an increase in projected MCP for those hours when the generation was withheld, more so in some hours than in others. Since hydro year 1998 represents wet conditions, it is quite possible that a similar strategy would produce greater increases in MCP under average or dry water conditions.

Backing off by 30 MW during peak hours in August reduces thermal unit's profits. The projected incremental fuel cost for this 30 MW of generation is about $981 per hour. An MCP of $70/MWh

48 As with the previous thermal withholding example, particular thermal generating capacity was selected for this illustration because the selected plant and its owner (in this case Southern Energy) represent large amounts of existing gas-fired capacity in northern California. This selection is for illustrative purposes and is not intended to suggest that Southern Energy is more or less likely to attempt to exercise market power than are any other owners of generation participating in California power markets.

would yield a positive income for running this 30 MW, with hourly revenues exceeding the hourly fuel cost by about $1100. (The MCP projected for various peak hours in August often exceeded $70.) However, if the MCP rises sufficiently due to withholding the 30 MW and if the owner has sufficient generating assets still producing in that hour, then the owner may increase overall income despite directly losing the revenues from running this 30 MW.

In fact, results indicated that in some hours merely owning a thermal plant portfolio the size of Southern Energy's was sufficient to make the withholding pay off, even without hydro ownership. For example, in hour 16 of August 5, the 30-MW reduction in output caused the MCP to increase by $0.99, so that lost income from withholding the 30 MW was more than offset by increased income at the 1,183 MW of remaining Southern Energy Company generation simulated to be sold into the market for that hour (Figure C-43).

For hour 17 of August 3 the 30-MW withholding produced a somewhat smaller MCP increase of $0.46/MWh. The original competitive MCP under the PowerMax Case was $76/MWh, so that the generator's owner needed to recoup about $1,300 ($2,280 revenues minus $980 of avoided fuel cost) from the rest of its portfolio, to break even. This is calculated to require having over 2,800 MW in the market for that hour and thus benefiting from the elevated MCP. Since the owner's thermal portfolio was simulated to be producing 1,510 MW (after the withholding), the owner would need about 1,300 MW of additional assets generating in that hour, in order to benefit from withholding. Adding the 734 MW Feather River portfolio is thus insufficient, but adding the larger 1,502 MW Feather + Pit portfolio is sufficient to make the withholding pay off, assuming that all hydro units are producing at full capacity in these peak hours (which may not be the case).

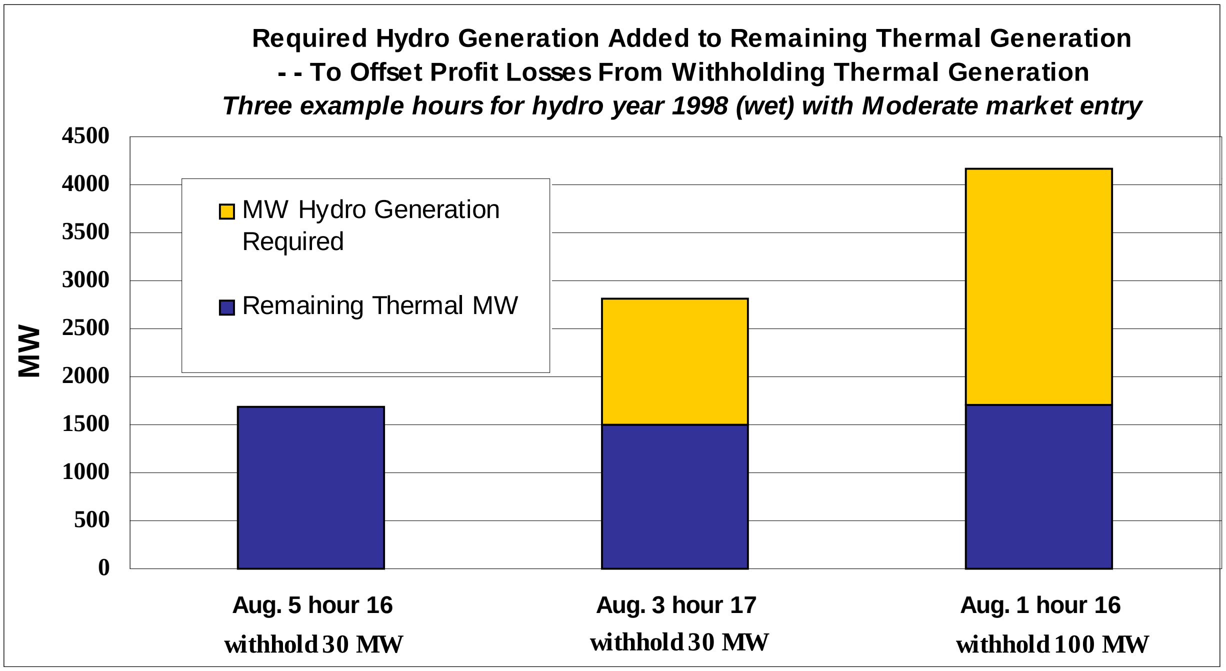


Figure C-43. Owning Enough Hydro Plus Thermal Generation Can Make Hourly Withholding of Thermal Generation Pay Off

A third hour provides additional insight. In hour 16 of August 1, withholding 30 MW produced no change in MCP, withholding 75 MW produced a $0.33/MWh increase in MCP, and withholding 100 MW produced a $1.08 increase. The latter withholding would pay off if in addition to projected thermal generation still in the market, the owner had at least 2,460 MW of hydro generation in that hour. This is somewhat more than the 2,241 MW represented by the 6-basin hydro portfolio number 6 (Table C-17). Larger withholding amounts might cause very large increases in MCP relative to the resulting income losses, so that smaller generation portfolios might be required for the strategy to be profitable. However, very large MCP responses to withholding might be viewed as symptomatic of a general shortage of capacity, rather than that of a market power problem. Clearly the potential for using a combined hydro-thermal generating portfolio to exercise market power varies considerably over the range of conditions analyzed to date and requires much more analysis.

6.3.4 Results: Market Power via Ancillary Services

One key aspect of hydroelectric generation is the ability to provide regulation, one of the "ancillary services" (A/S) required for reliable delivery of electricity. The opportunity for a generator to participate in markets for several ancillary services produces an opportunity cost for foregoing that participation by selling into the energy market. These "opportunity prices" can increase energy market bids and prices, relative to what would be expected in the absence of AS markets. Prices in the different markets rise or fall to levels that remove arbitrage between the markets, so that participants in the forward markets develop bids reflecting indifference to which market they are ultimately selected for.

The EIR preparers have investigated whether market power can be exercised by the owner of a hydro portfolio by withholding capacity from the regulation market in order to induce higher prices in both the energy and A/S markets. This withholding should increase the market price for regulation services, thus increasing the opportunity price for regulation, which in turn is reflected in increased energy bids (and prices). These higher energy and A/S prices can enable other units owned by the same supplier to recoup and even surpass the revenues lost due to the hydro portfolio not participating in the regulation market.

For illustration the EIR preparers simulated August 2005, with 1979 (“average”) hydro conditions and Proposed generator market entry. The EIR preparers assumed that a single owner controls the bidding strategy for a hydro portfolio consisting of the Feather River system, and compare two cases -- this portfolio’s participation versus non-participation in the ancillary service market for regulation. Table C-24 shows results for the first fifteen days of the month.

The significant revenue differences between the cases illustrate the value of proactive, strategic participation in all markets, to achieve better income prospects than provided by seeking maximum returns from energy markets alone. Another observation is that the greatest profit from withholding capacity in the AS market is projected for days with moderate, rather than highest loads. During these lower load days the hydro facilities tend to represent a larger fraction of the regulation market, and with fewer other units available to provide regulation up service, the price is higher.

Table C-24
Market Power Through Withholding Ancillary Services
Hydro Year 1979 (Average) With "Proposed" Generation Market Entry

Day	Daily Revenue ($)			Price Impact of Non-participation (withholding Impact		MW of Generation Required to Offset Lost Income Due to Nonparticipation in AS market
	Participate In PX & AS	Participate In PX Only	Lost Income by Not Participating In AS	Price Increase in Regulation Market $/MW/Day	Price Increase in the PX Market $/MW/Day	Generation Owned to Have Market Power MW
1	1564392	1280762	283631	45.57	-0.22	6254
2	1603992	1304058	299934	38.3	-6.52	9438
3	1481050	1190291	290759	32.68	10.34	6759
4	1423389	1154806	268583	67.96	20.36	3041
5	1297498	1058329	239169	78.11	17.30	2507
6	777867	621960	155907	85.14	30.67	1346
7	880288	710612	169675	73.99	24.03	1731
8	1434968	1200949	234020	66.09	9.15	3110
9	1561656	1316405	245250	46.29	13.94	4072
10	1603798	1338533	265265	24.74	9.27	7800
11	1609542	1339376	270166	64.86	9.22	3647
12	1512107	1255623	256484	59.95	-7.74	4913
13	1065417	886199	179218	101.77	25.13	1412
14	695597	585013	110583	100.56	47.53	747
15	1129055	935929	193126	116.79	26.03	1352

Of the days analyzed, August 14 shows the greatest opportunity for profiting from market power by withholding capacity from the regulation up market. Figure C-44 shows how this withholding strategy is projected to alter the pattern of utilization for the Feather River hydro system, and Figure C-45 shows the resulting impact on prices in the energy and regulation up markets.

The complex hourly patterns of energy market prices projected under original case are slightly altered by the simulated hydro portfolio nonparticipation in the regulation up market (Figure C-46). While Figure C-46 illustrates the absolute magnitudes of the energy prices, the change in hourly prices that is produced by withholding capacity from the AS market for regulation up is shown more clearly in Figure C-47. At the extremes, the price change ranges from a decrease of 6% to an increase of 10%, in different hours.

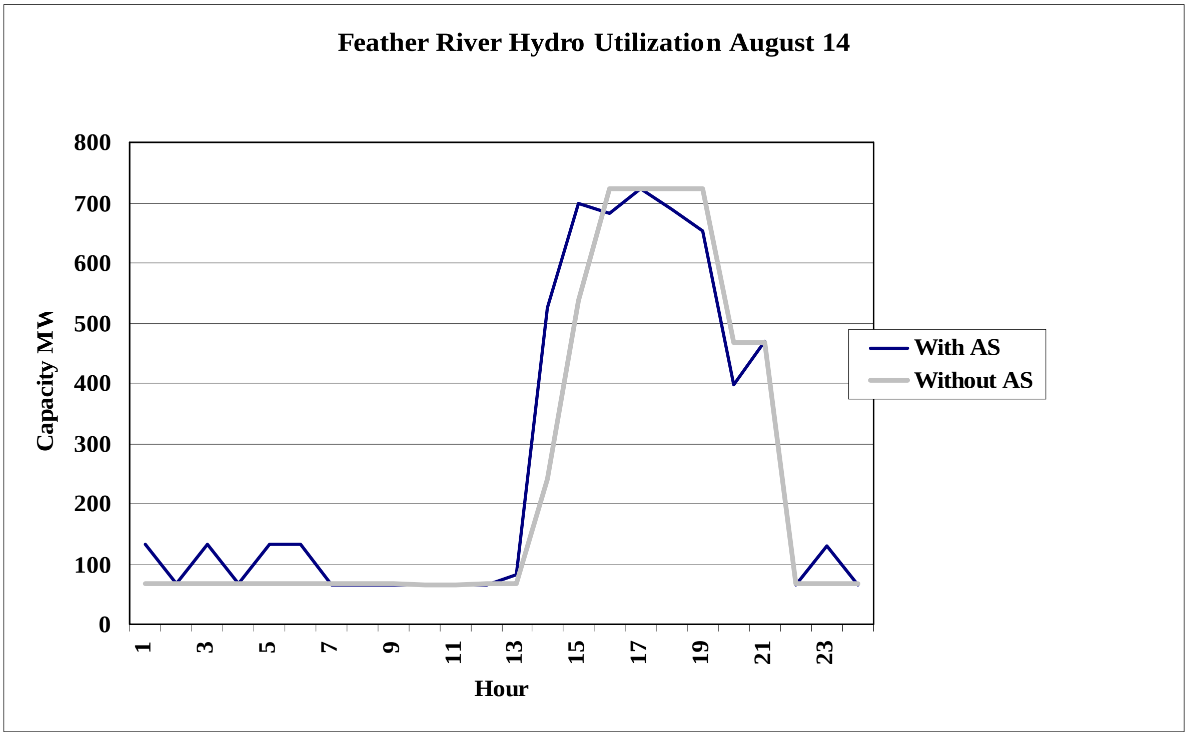


Figure C-44. Hourly Operation of the Feather River "Portfolio" With vs. Without AS Market Participation

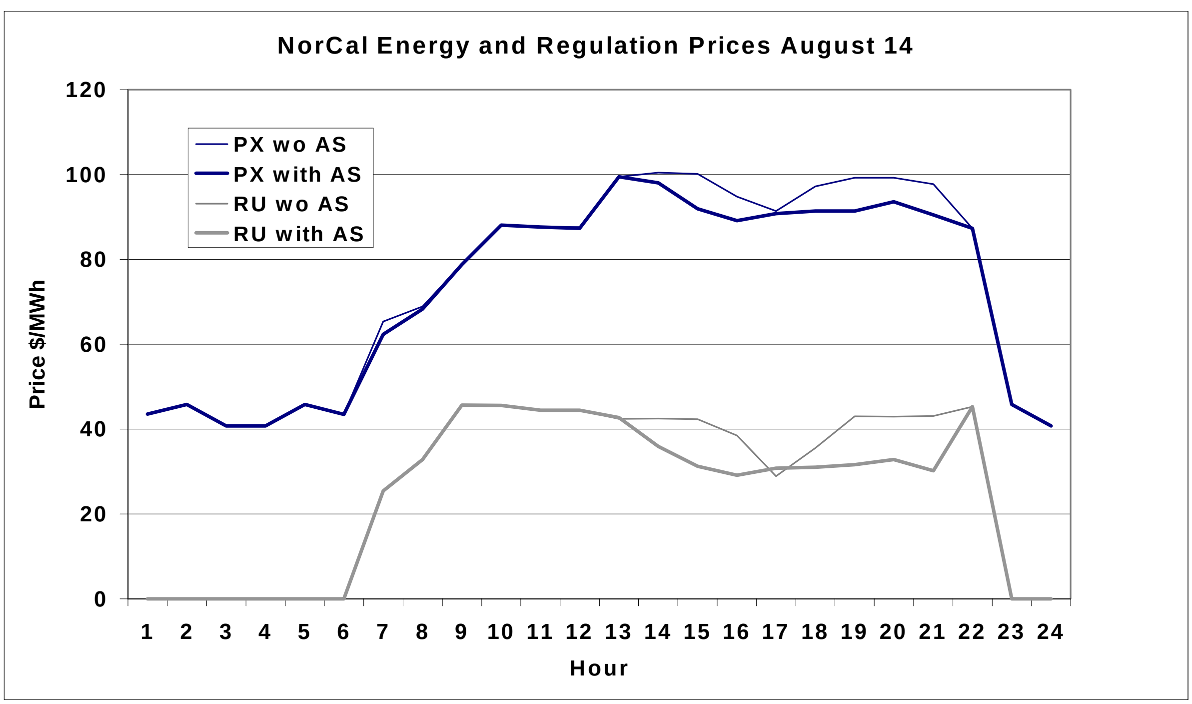


Figure C-45. Energy ("PX") and Regulation Up ("RU") Prices With vs. Without Feather River Portfolio Participation in AS Market

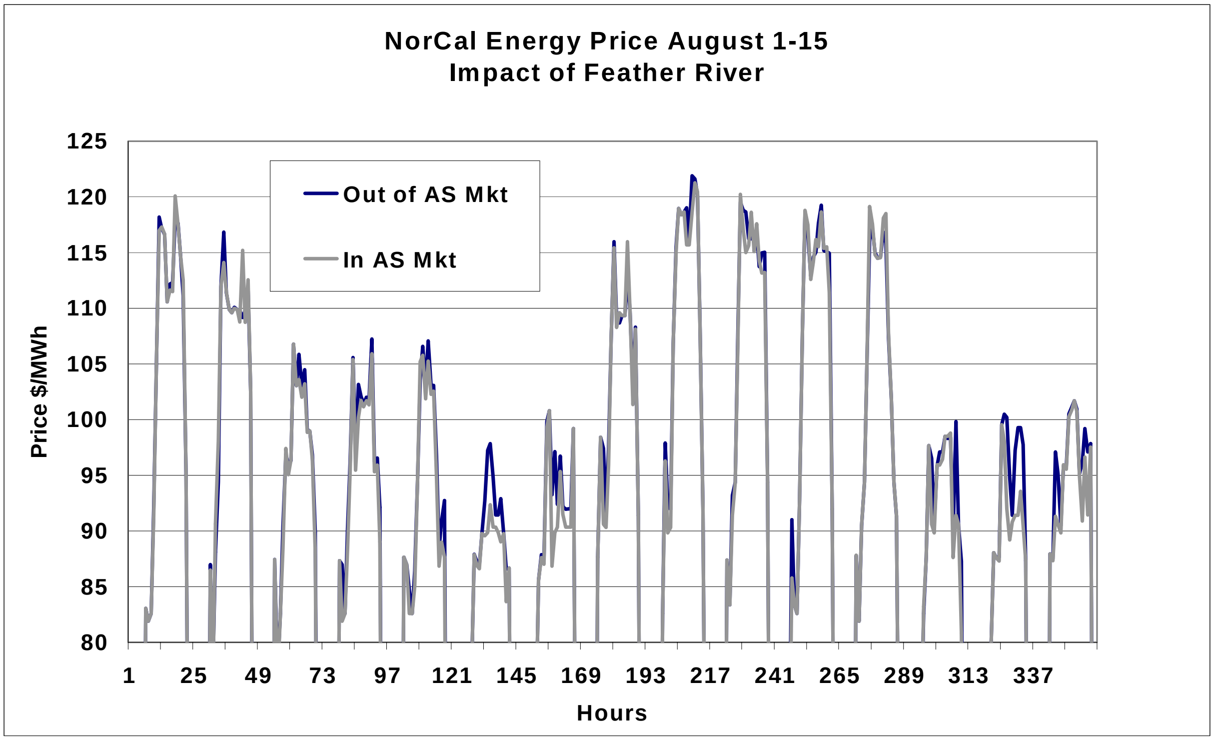


Figure C-46. Feather River Portfolio Non-Participation in Ancillary Services Market: Tweaking an Already-Complex Energy Market Price Pattern

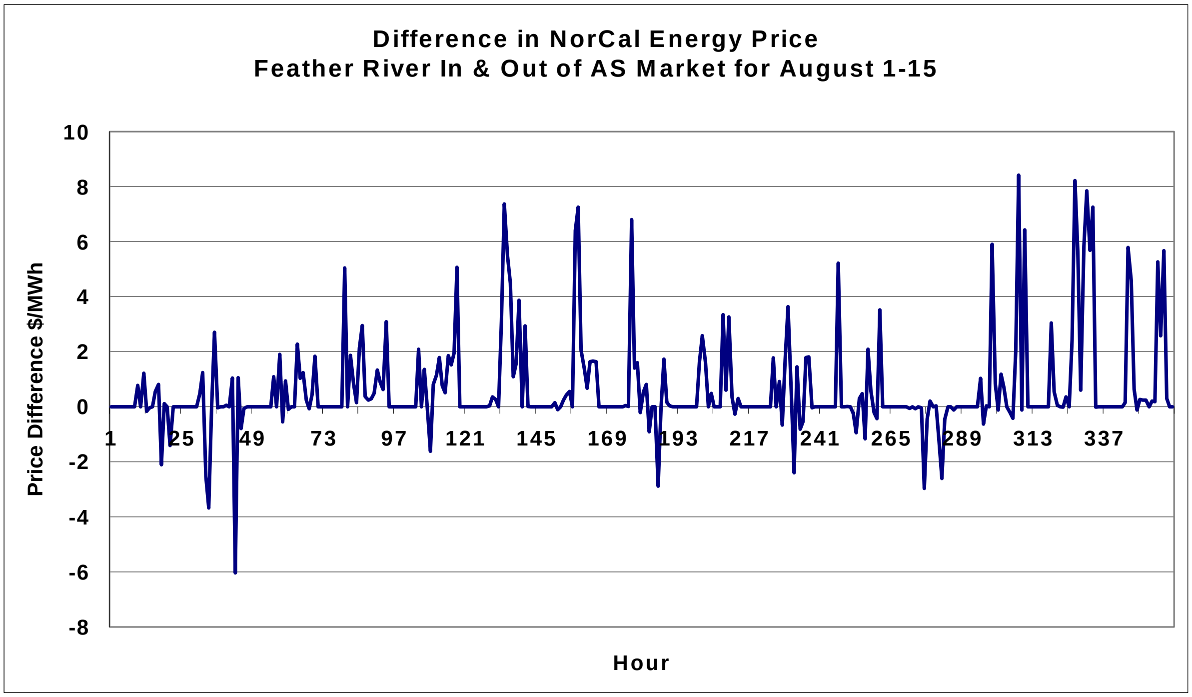


Figure C-47. Change in Hourly Energy MCP Due to Feather River Portfolio Non-Participation in Ancillary Services Markets

1979 (average) hydro conditions, "Proposed" market entry

The preceding cases illustrate opportunities for exercising market power that may exist through strategic utilization of the interaction of the multi-commodity markets for energy and ancillary services. If these opportunities are indeed highest during off-peak days, while hydro dispatch shifting described earlier provides additional market power opportunities especially during peak load conditions, there may be an attractive set of profitable, integrated market power strategies combining the two approaches. While the AS market strategy alone produced a small change in the simulated pattern of hydro generation (Figure C-44), the combined strategy could have a larger effect.

6.3.5 A Key Driver: Generation Supply Curves and Their Steep Points

This analysis indicates that under some conditions there is credible potential for exercising market power by shifting or withholding generation to increase energy and/or A/S market prices in California. This potential appears to vary dramatically across different seasons, hours, hydro conditions, and other circumstances. A key driver of this potential and its variation is the generation supply curve, including its shape and variation across time and changing conditions. The hourly supply curve represents the amount of additional MW of supply that is available for each step upwards in the $/MWh energy price, in that hour. If the curve rises steeply, as it does under certain conditions, then withholding supply can produce a large increase in the MCP, enhancing the prospects for exercising market power.

An understanding of this phenomenon can be obtained by examining supply curves for California. As an example, The EIR preparers have plotted a California supply curve[49] from the year 2005 simulation under 1976 hydro conditions and Moderate market entry, before any hydro generation shifting (Figure C-48). This curve represents the in-state generation supply for hour 12 (12 noon) of August 8, illustrating how certain parts of the supply curve give a steep increase in MCP for a given increase in supply (MW). When the system is at such points, potential practitioners of market power could achieve the greatest increase in MCP for a given amount of generation shifting or withdrawal.

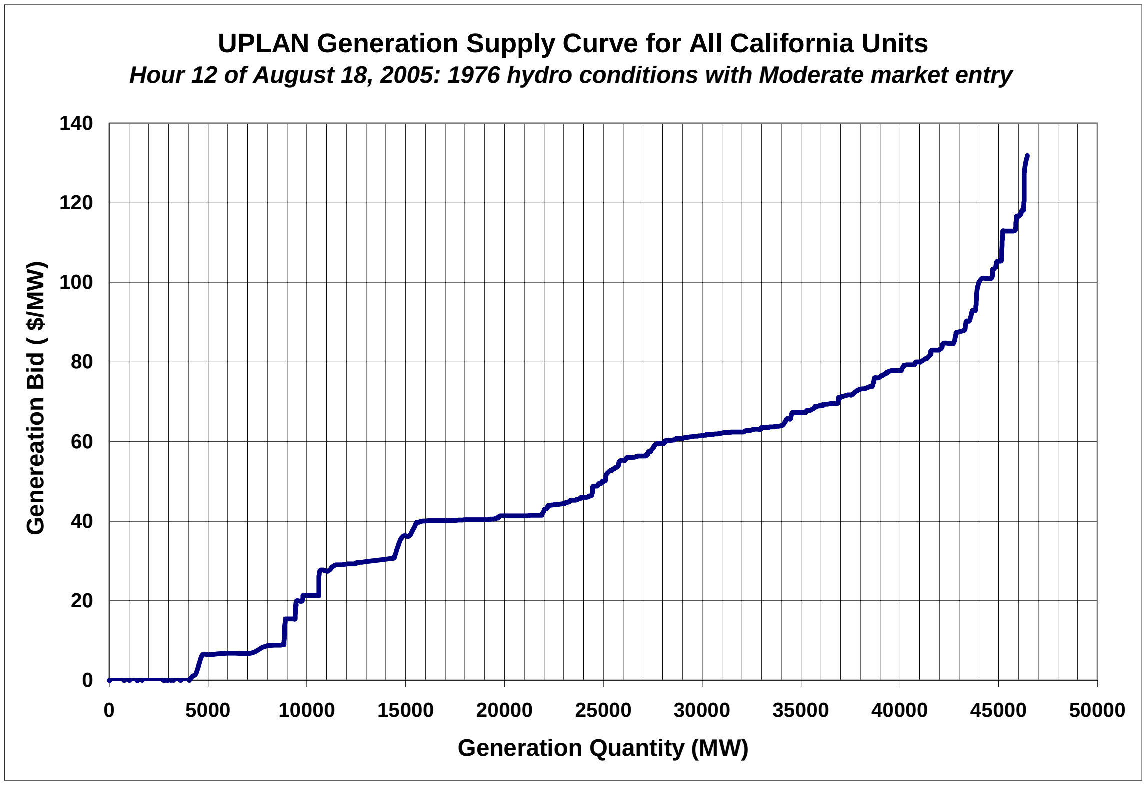


Figure C-48. UPLAN-Simulated Supply Curve for Generation Located In California

For example, in Figure C-48, if the load is at 22,000 MW, an additional 6,000 MW of supply (required if 6,000 MW is withdrawn or shifted) is associated with an MCP increase from roughly $40 to $60 (per MW, for this hour). Withdrawing 6,000 MW loses 6,000 MW X $40/MWh or $240,000 in revenues, which might represent a much smaller profit loss, depending on the operating costs and profit margin. On the other hand, any 12,000 MW of generation that remains in the market after such an MCP increase would receive a $240,000 increase in revenues (12,000 MW X {$60-$40}/MWh), the profit implications of which would also depend on operating costs.

49 The curve includes generating units located in California, but excludes out-of-state generators that also make a contribution to the simulated (and actual) supply of electric energy consumed in California.

The supply curve in Figure C-48 represents a particular hour, under particular conditions regarding loads, generator market entry and water supply. Under other conditions, the curve would change, shifting to the right or left under different water (hydro generation) conditions, and changing shape somewhat depending on the additions, retirements, or short-term commitment status of thermal generators.

The EIR preparers have also analyzed several actual supply curves from the California Power Exchange (CalPX) and observed similar pronounced bid (price) increases in certain parts of the curves. Figure C-49 shows one such PX supply curve, for noon of August 12, 1999. As in UPLAN-simulated supply curves, there are certain parts of the curves where price rises steeply for an increase in supply, such as at the supply level just above 34,000 MW.[50]

This analysis has observed that the potential for profitably exercising market power can vary considerably across seasons, hours, hydro conditions, loads, and generator market entry, not to mention other factors not analyzed, such as fuel prices. This variation is especially influenced by the location and size of the “steep” parts of the supply curve, and by what combination of conditions is being experienced by the market at any point in time.

50 Note that unlike the supply curve extracted from the UPLAN simulation (Figure C-48), the PX supply curve in Figure C-49 includes generation originating from outside of California. In fact, the UPLAN simulation includes markets and generation across the WSCC, including out-of-state generation imported into California. Also note that the length in MW of the relatively flat lower section of the curve (zero or very low $/MW) depends especially on hydro and coal generation, which in the PX supply come significantly from outside of California. (Water supply was above average in 1999 and below average in 1976.)

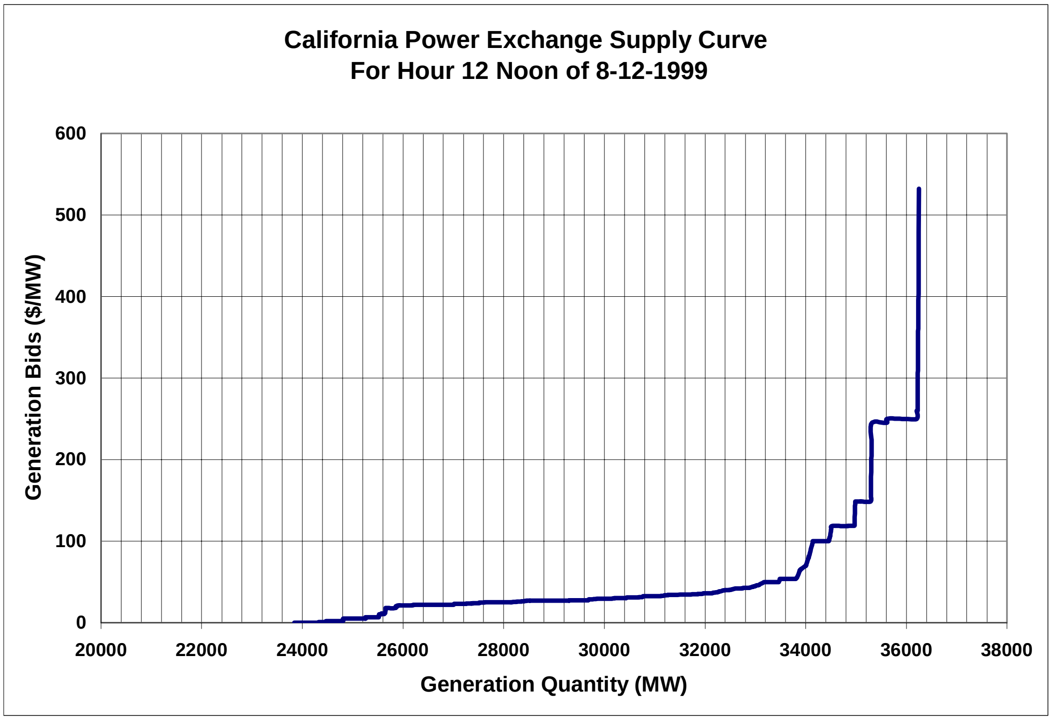


Figure C-49. California Power Exchange Generation Supply Curve for an Actual Peak Hour in August 1999.

6.3.6 Implications of the Market Power Analysis

This analysis covered a limited set of conditions that might be conducive to the exercise of market power, but it suggests the following key observations. The results indicate that under a range of conditions, a single owner with a portfolio of thermal plants in California could use those resources differently than might be the case in a competitive market to enhance portfolio profits through manipulation of market prices. In general, realistically achievable (in the real world) amounts of hydro and/or thermal plant ownership can confer an ability to exercise market power. The potential for profitably exercising market power appears to vary greatly over different hydrologic conditions, seasons and individual hours, and other circumstances that combine and interact. The projected ability to exercise market power by driving up market prices also strongly depends on what amount of new generator market entry is assumed or expected for the future. The dependence of the ability to exercise market power on these variables suggests that in the real world it might be challenging to anticipate the occurrence and duration of conditions conducive to exercising market power. Since efforts to profitably exercise market power would affect the patterns of utilizing hydroelectric and thermal power plants, they could have environmental consequences.