6.2 POWER MARKET SIMULATION RESULTS FROM UPLAN

6.2.1 Overview

Generator utilization and revenues, power flows and market prices in different zones of the WSCC were projected for 2000 and 2005 using methods, information and assumptions summarized in Section 5.1. For each divestiture case, UPLAN was used to model 24 sets of hydrologic conditions or "years" experienced by Pacific Gas and Electric Company and the WSCC overall, combined with electric loads, fuel prices and other electric generation resources anticipated for years 2000 and year 2005. The 24 different sets of water conditions representing historic conditions in years 1975-1998 had a significant impact on these results, reflecting the key role of hydroelectric generation in the WSCC. In addition, the different divestiture cases had a noticeable impact on projected generator utilization and revenues, and the resulting water use implications. Significantly, market prices differed little—on average less than one-half of one percent—among the primary divestiture cases. However, this was not true when the ability to exercise market power existed as analyzed in Section 6.3 below.

In simulating power markets in northern California and across the WSCC, UPLAN projected hourly operations of the powerhouses. These operations were simulated within various water use constraints, including the monthly water use schedules provided for different divestiture cases and hydrologic conditions. The water release implications of these powerhouse operations are relevant to subsequent environmental analyses.

Market clearing prices (MCP) for electric energy projected for the northern California pricing zone provided two important kinds of information. First, the MCP projected under different hydrologic and divestiture conditions provide a temporal pattern of price signals influencing how future owners of the hydro facilities might adjust operations to improve profitability. For this reason, WRMI's OASIS model was run iteratively with UPLAN to develop revised monthly hydroelectric generation schedules based on UPLAN-generated market price (see Figure C-1). The projected MCP also provide information on how power markets can be affected by the different hydrologic and divestiture conditions analyzed, under circumstances forecast for 2005 regarding electric loads, generators, fuels, and transmission.

First we describe the hydro powerhouse operations projected by UPLAN under different hydrologic and divestiture conditions. Hourly results are illustrated for certain key basins, aggregating results for the individual powerhouses within each basin. Basin-wide generation translates into water releases at the powerhouses, affecting water flows and reservoir levels in the basin on an hourly, daily and seasonal basis. More localized and/or short term water flow and storage consequences may depend on operations at specific powerhouses, depending on how storage buffers the effect of water releases, and on how water is diverted into canals, tunnels and powerhouses as opposed to natural streambeds.

Finally, we provide an overview of all-hours and on-peak market clearing prices (MCP) for electric energy, projected for the northern California pricing zone under the different hydrologic conditions and divestiture cases. These results are provided for the full set of 24 hydro years, for each case, on a daily basis.

6.2.2 Projected Hourly Powerhouse Output: Effect of Hydrologic Conditions

In some of the water basins, the Pacific Gas and Electric Company powerhouses being considered for divestiture are essentially all run-of-river plants with little or no ability to time their generation. They offer limited operational flexibility with or without divestiture. Except for certain streamflows assumed to be purchased under the Proposed Settlement Case (no longer diverted through powerhouses), these systems were modeled to continue their historic monthly patterns of generation under each of 24 sets of hydro conditions. Examples include the Kilarc, Cow Creek, Butte Creek/DeSabla, and Kern Canyon powerhouses, all of which were modeled to have slight water availability reductions (for generation) under the Proposed Settlement Case, but otherwise to operate the same across the different divestiture cases.

In contrast, powerhouses in other basins have sufficient storage to adjust operations in response to power market conditions. The greater the amount of storage relative to water inflows, the greater the time period over which generation levels can be managed, seasonally for large amounts of storage, among hours of the day for smaller amounts of storage. This flexibility is constrained by various formal and informal restrictions on water use (assumed to vary across the divestiture cases) and by control of water rights and/or upstream releases by other parties.

This Section describes some of the hourly modeling results regarding generation and water use for three of the larger components of Pacific Gas and Electric Company's hydroelectric system, in the McCloud-Pit, North Fork Feather River (NFFR) and Mokelumne basins, respectively. These three systems contribute substantially to total Pacific Gas and Electric Company hydroelectric generation, averaging about one-third, 25%, and 10% of total conventional (non-pumped) Pacific Gas and Electric Company hydroelectric generation, respectively. They also received considerable attention in analyses for the divestiture EIR, because of their size and operating flexibility. Section 6.2.2 focuses on effects of different hydrologic conditions, under the Baseline and No Project divestiture cases. The effects of the different divestiture cases are smaller, and generally do not override the effects of the different hydrologic conditions, and are discussed in Section 6.2.3.

Example UPLAN Hourly Generation/Flow Projections: McCloud-Pit System

The three systems noted above differ considerably regarding hydrology and potential for altering operations in response to ownership and market circumstances. The McCloud-Pit system has only moderate amounts of usable storage, relative to the large water flow volumes typically available for generation throughout much of the year. The porous volcanic aquifers and large springs in the region act as quasi-reservoirs, but the discharge cannot be controlled. As a result, flexibility to time generation is limited in that water often must be used or else lost (spilled, rather than diverted for generation). This means that much of the winter/spring runoff must be used rather than stored, so that generation is typically highest in winter and spring. This leaves limited potential to shift generation into the summer period to capture high market prices, as discussed in Section 5 regarding the monthly water use schedules provided for UPLAN modeling. However, there is some flexibility to time generation on an hourly basis over the course of a week.

The flow duration curves for the McCloud-Pit system in winter and summer (Figures C-5 and C-6) depict the percentage of the time that MW output (requiring water flow through powerhouses) exceeds various levels.[32] We can see that for a considerable portion of the hours in winter or summer, generation is at the maximum level, indicating water being released from storage for generation at full powerhouse capacities, typically during peak hours. At the other end of the curves, except in the wettest years a considerable number of hours are spent at the minimum generation levels, representing run-of-river generation (plants without significant water storage) plus minimum required releases at some facilities with storage. Overall, these curves indicate

32 Water flow through turbines may contribute to or reduce (by diversion) water flow in particular reaches of natural watercourses, depending on the locations (of powerhouses and watercourses) and times considered. However, the overall pattern of generation and associated water releases is a useful, broad

- limited ability to store water from the winter to the summer, so that generation is higher in winter (November-April), and
- greater but still limited ability to store water and time generation on a daily basis within a week or month, so that minimum levels of generation (and water throughput) are projected to occur in less (usually much less) than half of the total hours

In essence, this system has high water flows and limited water storage, so that maximum (full capacity) water releases and generation occur more often than minimums. Projected basin-wide generation (and water flow through powerhouses) in the winter (November through April) is at the maximum, full capacity level between one-third of the time for the driest year to 75% of the time for the wettest year, and somewhat under half the time for an average year (Figure C-4). For the summer (May-October), this drops to a range of about 25% (driest) to about half (wettest) of the time, and about one-third of the time for an average year (Figure C-5). Note that while 1979 was an average year for the overall Pacific Gas and Electric Company hydro generation, it was somewhat on the low (dry) side for the McCloud-Pit system.

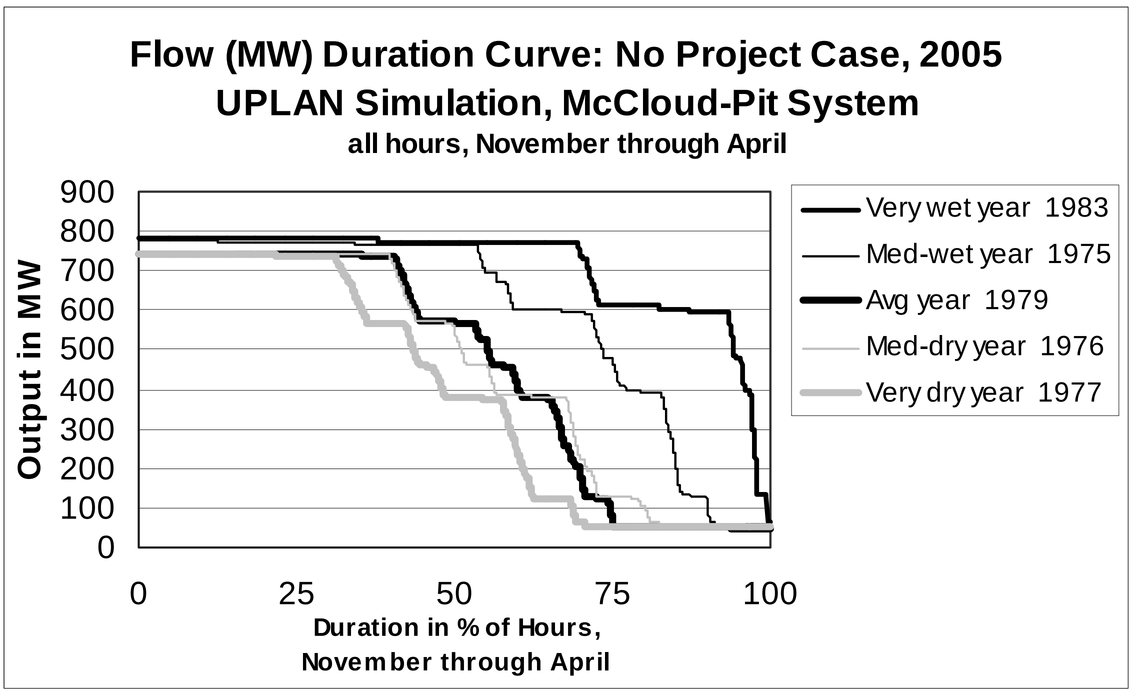

Figure C-4. McCloud-Pit System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

As noted, the minimum generation level represents generation from only run-of-river plants plus required minimum releases through powerhouses from storage. In the winter this is projected to

indicator of changes or variations in hydroelectric operations, potentially of significance for the surrounding environment.

occur about one-third of the time in the driest year, hardly at all in the wettest year, and less than 25% of the time in an average year (Figure C-4). In the summer this rises to about 40% of the time in average and dry years, and about 15% of the time in the wettest years (Figure C-5).

The value of water storage is being able to generate at highest levels during peak hours when market price are highest. Here, the peak hours are defined as 6 AM to 10 PM on weekdays. During the summer, the McCloud-Pit system is projected to generate at the maximum level for virtually all peak

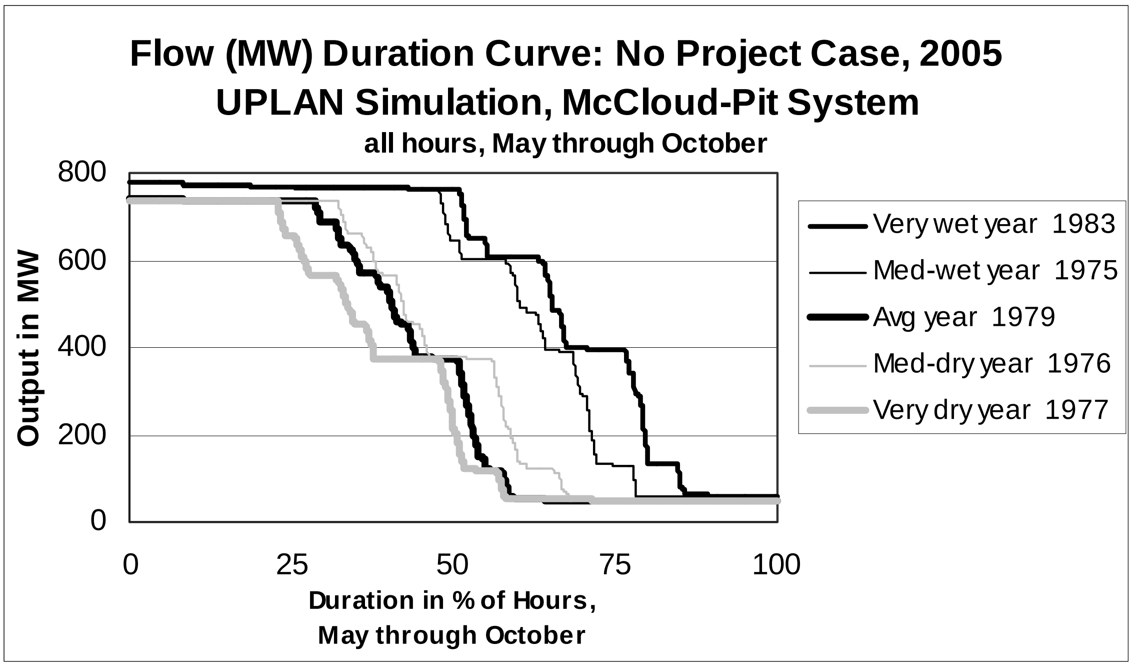

Figure C-5. McCloud-Pit System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

hours during wet years, and for more than 60% of peak hours under all except the driest conditions (Figure C-6). In winter, with higher water flows (yet limited storage) these percentages rise, with maximum generation levels being reached during almost all peak hours in the wettest years and for more than 75% of peak hours in all but the driest years. Generation is not projected to fall to minimum levels during peak hours, except for a few summer hours in the driest years.

The seasonal MW (water flow) duration curves (Figures C-5 and C-6) and the high frequency of maximum generation during peak hours (Figure C-6) reflect a daily cycling pattern in which powerhouses with access to water storage time their generation (water releases) to occur during hours of the day when market prices are highest. This gives rise to a seven-day cycling pattern, with highest generation levels (often maximum levels) occurring during the high-load (high price) hours of each day (Figure C-7). This daily pattern is most pronounced in the summer due to high mid-day loads for air conditioning. Because weekdays generally have higher loads than weekends, the projected duration of high (especially maximum) generation levels is shorter on weekends, represented by the first and seventh cycles (days) in Figure C-7. Under most hydrological conditions, there is projected to be less available water and less generation towards the end of the summer and into the fall, so that the number of daily hours with high or maximum generation is projected to decline. As noted before, the minimum generation levels visible in this daily cycling pattern (Figure C-7) represent run-of-river generation (that cannot be timed) plus minimum releases for storage-based generation.

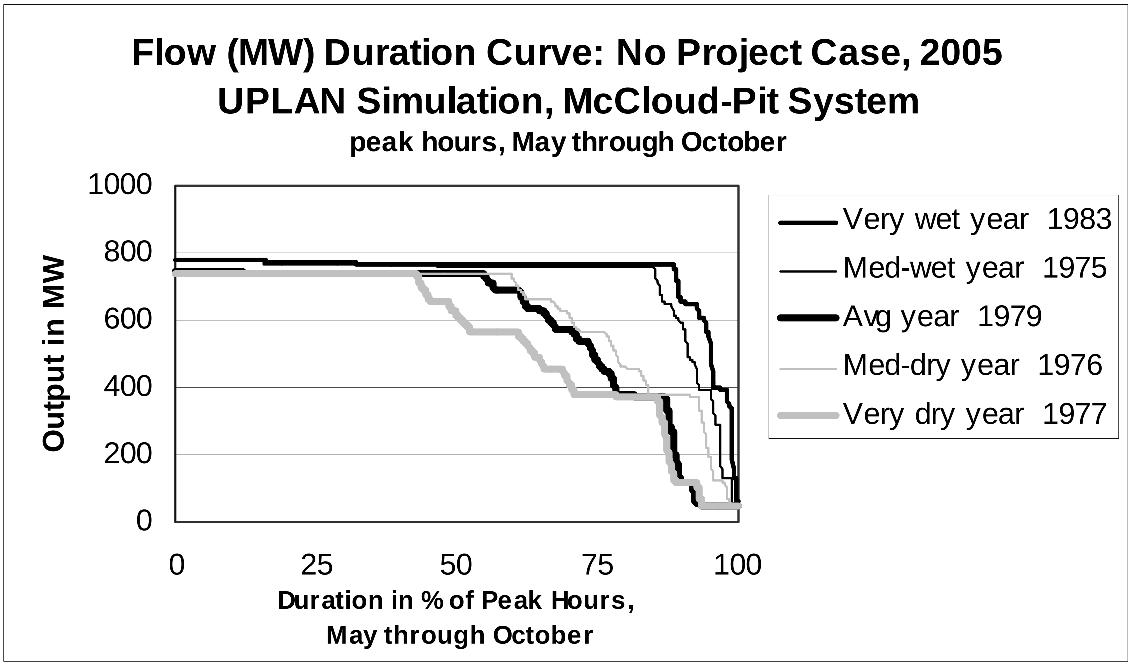

Figure C-6. McCloud-Pit System Hourly MW Duration in Summer On-Peak Hours
No Project Case, comparing five hydro years all projected for 2005

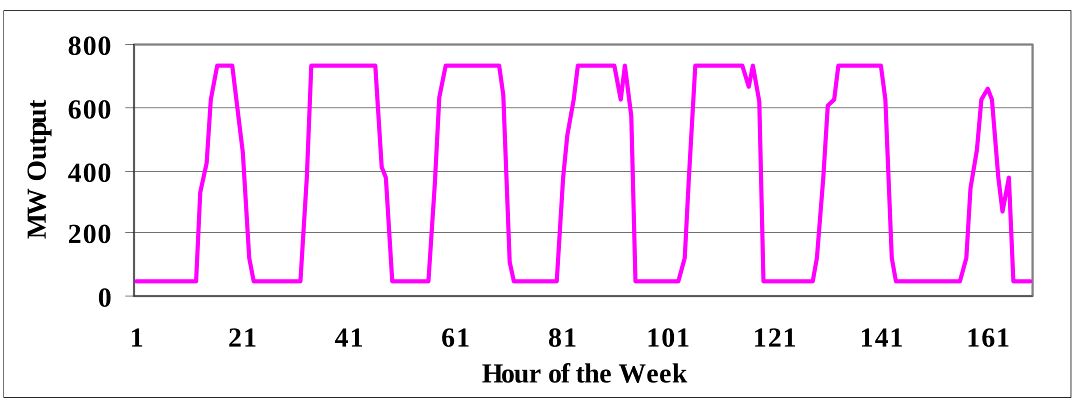

Figure C-7. McCloud-Pit System Chronological MW Output, Week of July 24, 2005
UPLAN Simulation, No Project Case for hydro year 1979 (average conditions)

During the off-peak hours, lower market prices are encountered, generation is generally is reduced to lower and often minimum levels, and water is accumulated in storage for use during the next period of high prices. However, generation during off-peak hours will exceed the minimum level when the available water exceeds the amount that can be stored for, and used during, the peak periods. This is especially influenced by the storage capacity relative to the rate of water inflows. In some off-peak hours of some months, water must be used to generate above the minimum level rather than being saved for peak (high price) periods, or else it will be lost for purposes of generation. Thus, with relatively high water flows throughout the year, projected McCloud-Pit system generation exceeds minimum levels in about two-thirds of the summer off-peak hours in wet years and about 25% to half of the summer off-peak hours in average-to-dry years (Figure C-8). In winter, with higher water flows, these percentages are even higher, 80-100% of the time for wet years, and 50-60% of the time for average-to-dry years.

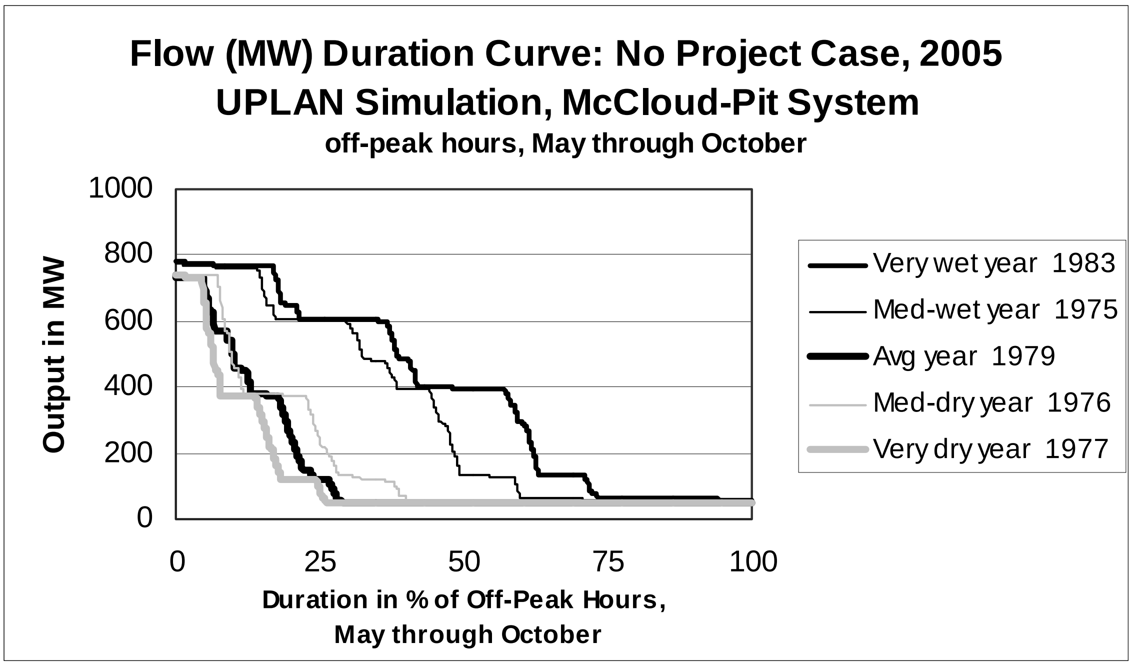

Figure C-8. McCloud-Pit System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

Example UPLAN Hourly Generation/Flow Projections: North Fork Feather River System

The North Fork Feather River (NFFR) system experiences more seasonal and year to year variation in water availability than does the McCloud-Pit system. This results in greater variation in projected (and historic) generation across the different hydrological conditions represented by the

24 hydro years analyzed.[33] This variation is reflected in the monthly water use and generation levels provided for UPLAN modeling of the 24 different hydro years. It is also reflected in the winter and summer MW duration curves for the NFFR system across five different hydro years (Figures C-9 and C-10).

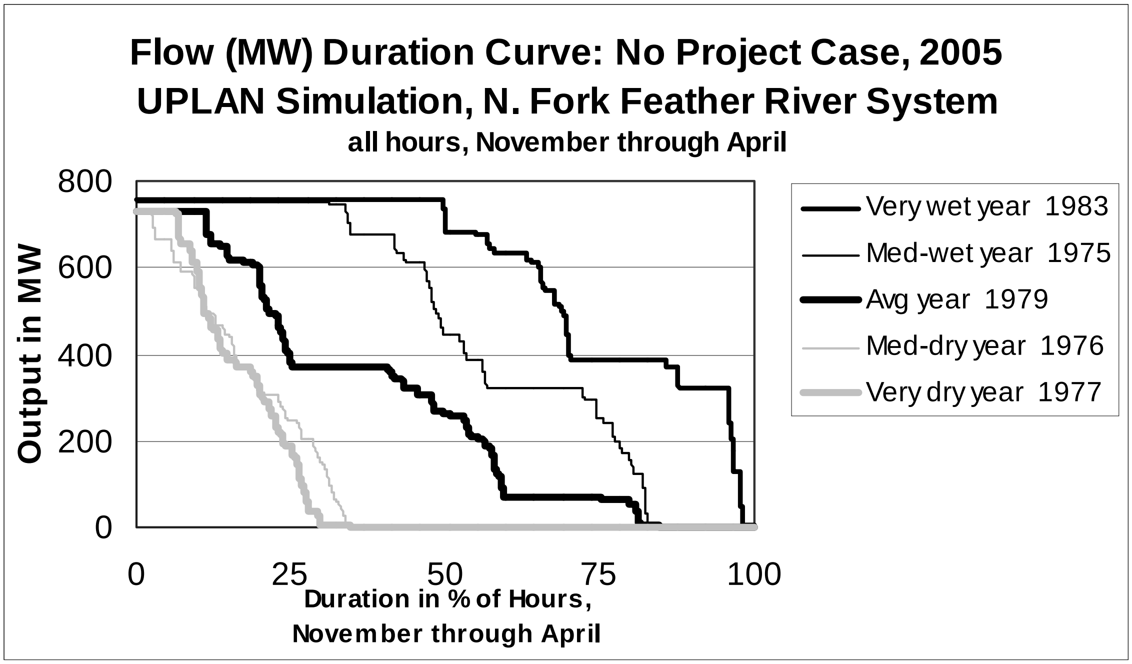

Figure C-9. NFFR System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

The NFFR system accounts for the second largest portion of Pacific Gas and Electric Company's hydroelectric generation (after the McCloud-Pit). This system has both large inflows and very large amounts of storage, giving considerable ability to control levels of generation and water release on a seasonal as well as daily basis. This is reflected in the optimized monthly generation pattern provided for UPLAN modeling, in which generation levels are actually highest in later months of the year due to releases from storage, especially in drier years, although not in the wettest years. This is reflected in the MW duration curves from UPLAN modeling (Figures C-9 and C-10). Besides permitting winter-spring runoff to be stored for use in the summer, the considerable storage in this system also can be used to coordinate generation with high load (high market price) periods on a daily and hourly basis. It also provides the potential to alter operations under different market and ownership circumstances in the future. For these reasons, and because of the large amount of generation it represents (about 25% of conventional Pacific Gas and Electric

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33 This analysis does not include any changes in FERC licensing conditions or other operating practices that may arise out of the recently proposed relicensing settlement for the Rock Creek-Cresta Project (FERC No. 1962).

Company hydro generation), the NFFR system received considerable attention in this study's evaluation of potential operating and water use changes under different divestiture cases.

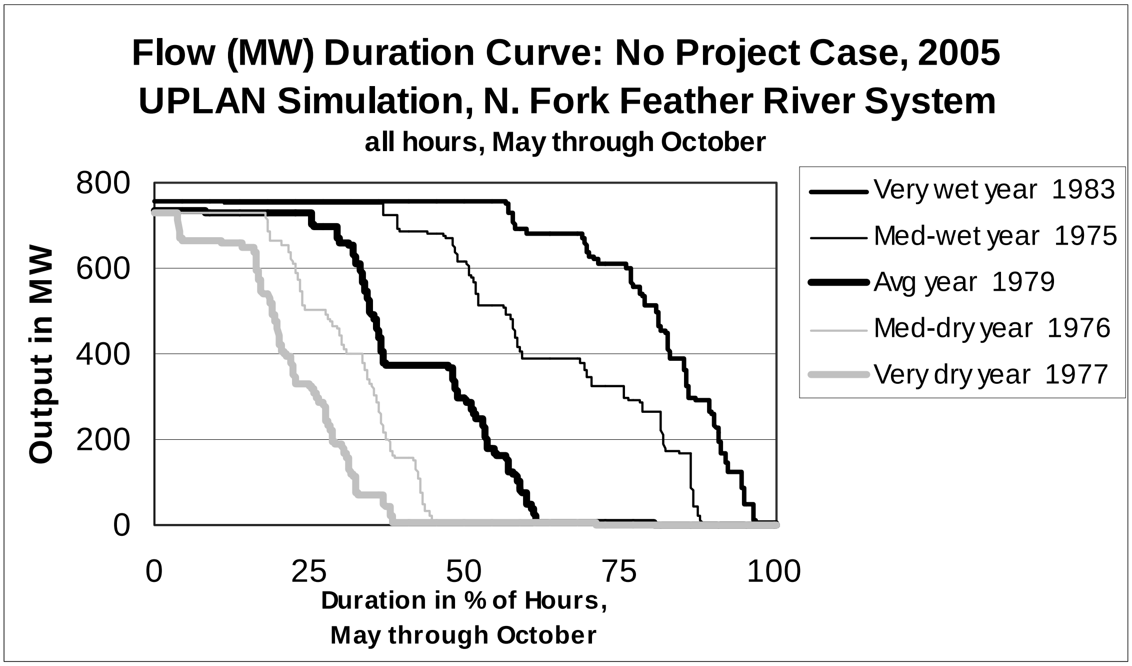

Figure C-10. NFFR System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

The flow (MW) duration curves indicate that compared to the McCloud-Pit system the NFFR system is projected to operate at maximum generation levels (full capacity) for less of the time in the winter, especially in dry years. The range is from just under half of the hours in wet years to 10% or less of the hours in dry years (Figure C-9). Also in the winter, minimum generation levels (minimum water passage through powerhouses) are projected to be reached about two-thirds of the time under dry conditions (more frequently than for the Pit system) and about 5-15% of the time under average-wet conditions (similar to the Pit system). This reflects filling of storage during winter-spring runoff, rather than having to use much of the runoff for immediate generation (or else lose it). The NFFR contains little generating capacity that is fully run-of-river or that has substantial minimum required flows through powerhouses, explaining why the minimum generation level is lower than for the McCloud-Pit system.

In the summer (Figure C-10), the situation is entirely different due to the considerable storage and flexibility to manage it. For summers (May-October) of wet hydro years, maximum generation is projected to be reached about half of the time, as in McCloud-Pit system. Due to use of stored water, generation is projected to drop to the minimum level less than 10% of the time, less often than for the McCloud-Pit system.

However, in dry years less water is stored and maximum generation levels are projected to be reached for only about 5-15% of the summer hours, less than for the McCloud-Pit system. Generation is projected to drop to minimum levels more often than for the McCloud-Pit system, about 60% of the time. In essence, with its considerable storage the NFFR system has a lot of water to use for generation in the summers of wet years, but in dry years smaller amounts of stored water mean lower overall summer generation and more hours at minimum generation levels.

The considerable water storage gives the NFFR system ability to time generation for peak hours when market prices are highest, especially in average-to-wet years when storage levels are high. During the summer (May-October), the NFFR system is projected to generate at maximum capacity for 70-90% of peak hours during wet years, about half of peak hours in average years, but only 10-30% of peak hours in dry years (Figure C-11). Especially for dry years, this is a smaller percentage of peak hours at full capacity than projected for the McCloud-Pit system, and the difference between wet and dry years is considerable. In the November-April winter period when water runoff is being stored, the projected percentage of on-peak hours spent at full output capacity is lower than in summer, the opposite of what was projected for the McCloud-Pit system with its smaller storage relative to runoff. NFFR generation is rarely projected to fall to minimum levels during peak hours of average-to-wet years (winter or summer), but is projected to fall to minimum levels in about 25% to one-third of peak hours in dry years (more often in winter). This is more frequently than projected for the McCloud-Pit system.

Similar to the McCloud-Pit and other systems with usable water storage, the NFFR system is projected to operate on a daily cycling pattern, running at high or maximum output during highest load hours in the middle of the day and evening (especially on weekdays) and running at low or minimum output during off-peak hours in the early morning. (See Figure C-7 for the McCloud-Pit system.) High loads and high output are less frequent on weekends. The minimum generation level is set by run-of-river generation plus minimum water releases through powerhouses, and the maximum level is set by powerhouse capacities (water turbines, turbogenerators, water delivery). However, the duration of maximum generation levels during a week is driven by the duration of high loads during that week relative to other periods, and by availability of water to release from storage.

During off-peak hours[34] with low market prices, storage hydro generation is reduced, usually to minimum levels, to preserve water for use during high load periods. When water is used to generate above minimum levels during off-peak periods this is generally because so much water is available that the most economic option is to use some of it for generation even during off-peak hours. In the summer, off-peak generation from the NFFR system is projected to exceed minimum

34 Here, "off-peak" includes all weekend hours, even though storage hydro may be cycled up during some high-price hours on the weekend as shown in Figure C-7.

levels roughly 80% of the time in wet years, but only about one-third of the time in a typical average year and about 10-15% of the time in dry years (Figure C-12). For wet years, above-minimum generation in summer off-peak hours is thus more frequent than was projected for the McCloud-Pit system, but for dry years

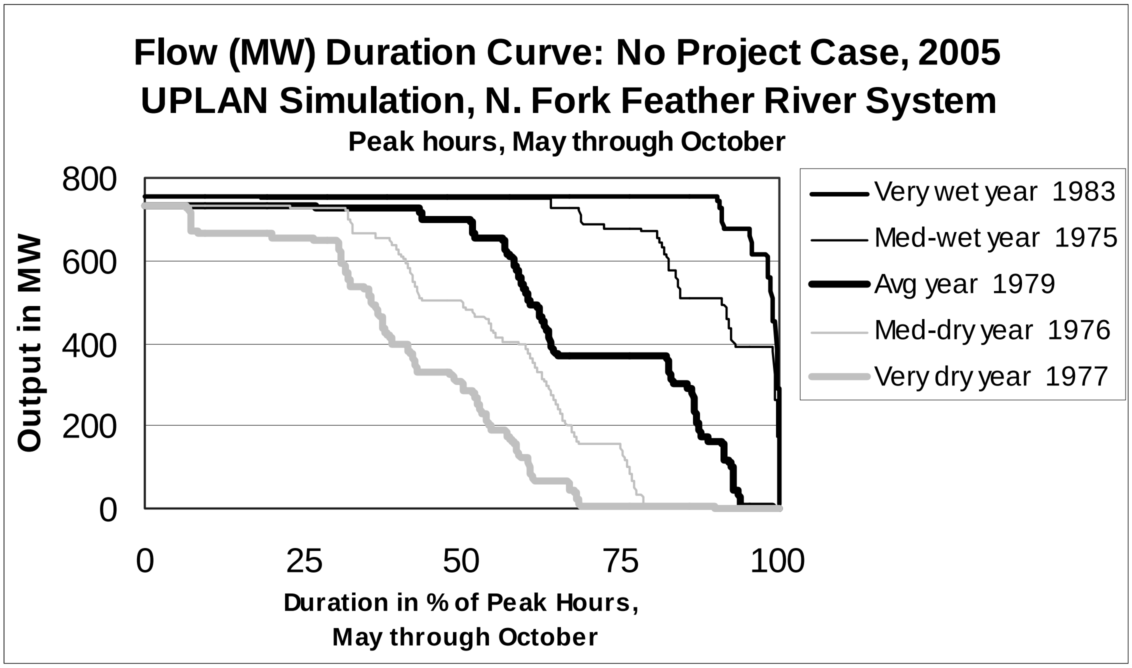

Figure C-11. NFFR System Hourly MW Duration in Summer On-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

it is less frequent (about the same for average years). This reflects abundance of stored water in summers of wet years, and unused storage in summers of dry years. In winter, the projected frequency of off-peak generation above minimum levels is about the same as in the summer under wet conditions, but under dry conditions it is rare (water would be going into unfilled storage for later use).

Example UPLAN Hourly Generation/Flow Projections: Mokelumne River System

The Mokelumne River system in the central Sierras has enough storage to provide some seasonal as well as hourly control over generation and water releases.[35] However, flexibility to time water releases and generation is constrained by the complex interconnected system of canals and tunnels, by water agreements, and because roughly a quarter of the generation comes from run-of-river

35 This analysis does not include any changes in FERC licensing conditions or other operating practices that may arise out of the recently proposed relicensing settlement for the Mokelumne Project (FERC No. 0137).

plants with little effective storage. Since the amount of generation from run-of-river plants varies considerably by year and season, the modeled "maximum" and "minimum" generation levels also vary significantly by year and season. This is apparent in the flow (MW) duration curves for winter and summer (Figures C-13, C-14). On a percentage basis, generation in the Mokelumne River system varies among hydro years (wet versus dry conditions), about as much as it does for the NFFR system.

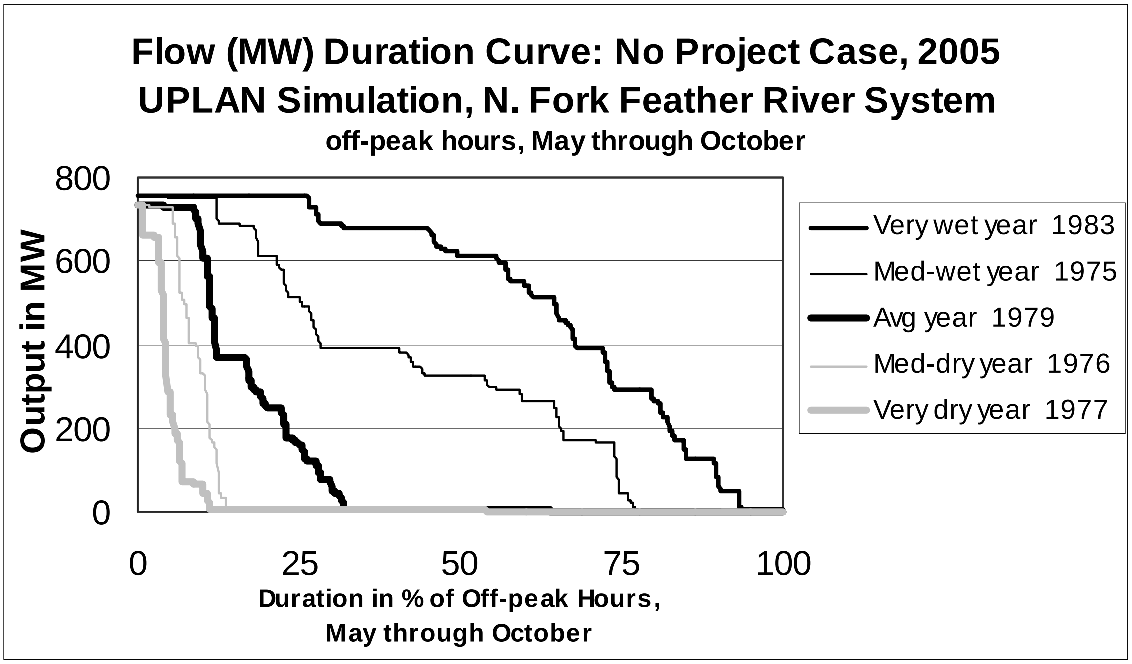

Figure C-12. NFFR System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

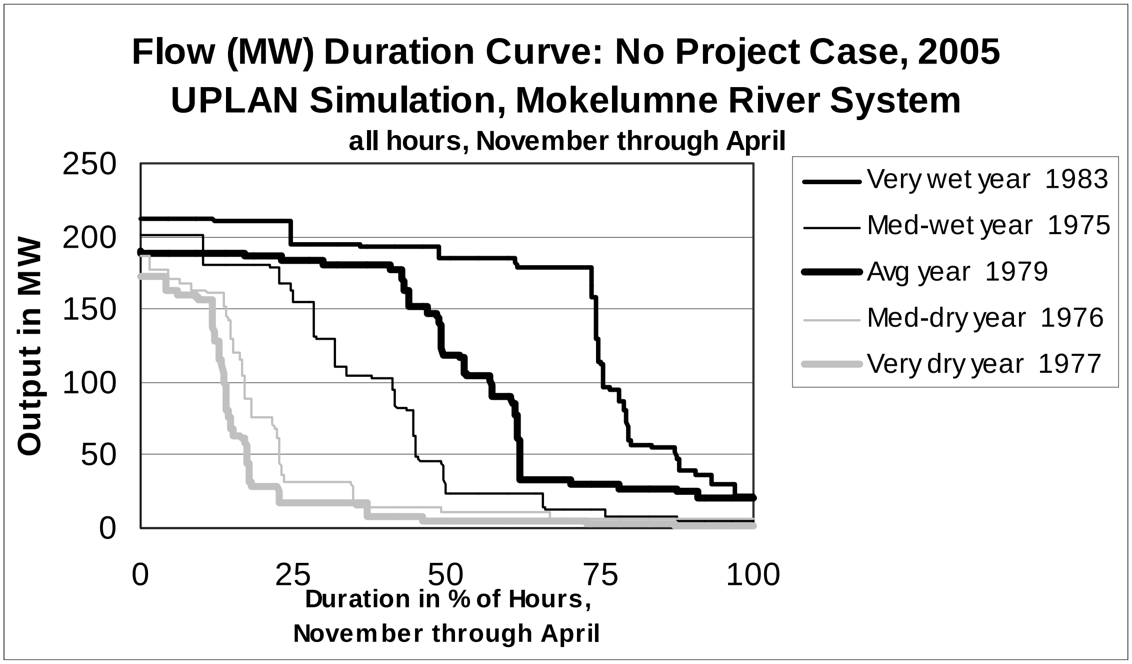

Figure C-13. Mokelumne River System Hourly MW (Flow) Duration in Winter

No Project Case, comparing five hydro years all projected for 2005

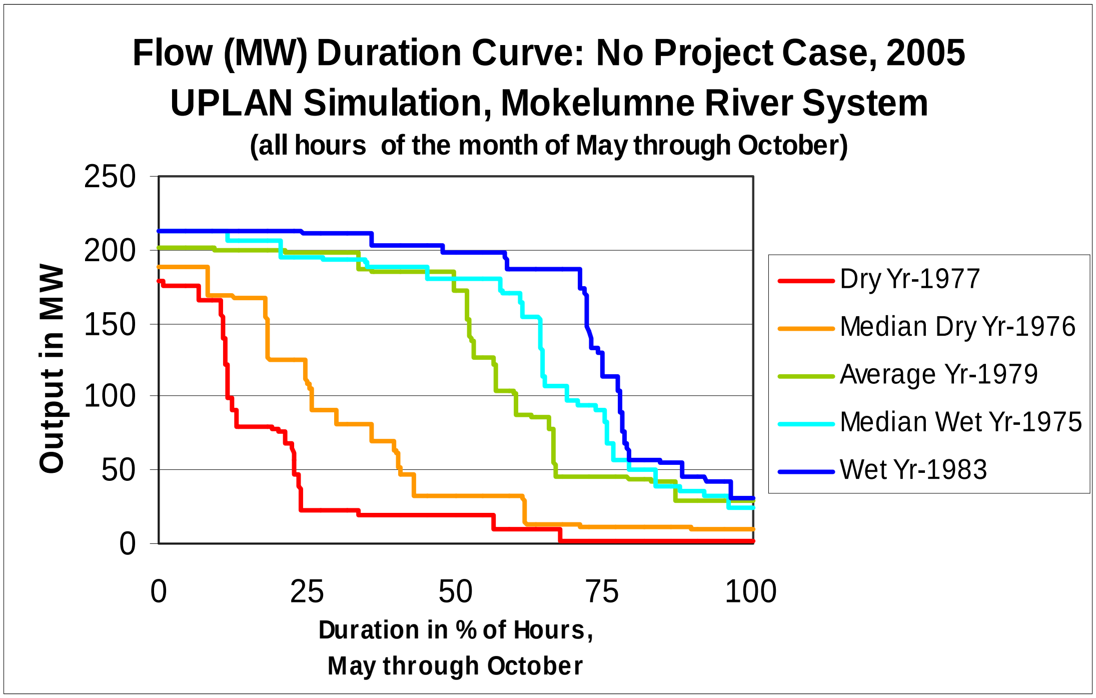

Figure C-14. Mokelumne River System Hourly MW (Flow) Duration in Summer

No Project Case, comparing five hydro years all projected for 2005

In general, projected generation levels for the Mokelumne River system are about equal in the winter and summer in the wettest years, but otherwise are somewhat higher in summer (Figures C-13, C-14). This reflects use of water from storage. The MW levels representing "maximum" and "minimum" generation vary noticeably between months and among the 24 different "hydro years." This reflects variation in run-of-river generation, which plays a larger role here than in the Pit or NFFR systems.

In the winter period, maximum (full capacity) output is projected to be attained for about 75% of the hours under wettest conditions, in somewhat less than half of the hours under average-to-wet conditions, and in only about 15% of the hours under dry conditions (Figure C-13). This is slightly more often than is projected for the NFFR system. In winter, generation is projected to drop to minimum levels about 15% of the time under the wettest conditions and almost half of the time under average-to-wet conditions, similar to what is projected for the NFFR. Under dry conditions, minimum generation levels are projected to be reached more than two-thirds of the time in winter. This is also similar to what is projected for the NFFR system, and reflects filling of storage.

In the May-October summer period (Figure C-14), the situation is altered, reflecting use of stored water. Maximum generation levels are projected to be reached in about two-thirds of the summer hours during average-to-wet years (more often than in winter) but in only about 10-20% of the hours in dry years (a little more often than in winter). This is a slightly higher frequency of reaching maximum output than is projected for the NFFR system in the same hydro years. Generation is projected to drop to minimum levels about 25% of the time in summers of average-to-wet years, but about half to 75% of the time in summers of dry years (about as often as in winter). This represents more hours at minimum generation than projected for the NFFR system, especially in the driest years. However, due to run-of-river generation, the Mokelumne minimum level is higher.

Water storage in the Mokelumne River system provides ability to time generation for peak load hours when market prices are highest. During the summer period of May-October, maximum output levels are projected to be reached in 90-100% of the peak hours during wet years, in about 75% of the peak hours in a typical “average” year, and in 25% to half of peak hours in dry years (Figure C-15). This is a slightly higher frequency than projected for the NFFR system, although the MW level representing “maximum” generation varies noticeably over time due to the influence of run-of-river generation. In the November-April winter period, water runoff is being stored and the projected frequency of attaining maximum generation during peak hours drops slightly, except in the wettest years. As with the NFFR system, the difference between wet and dry years is considerable.

Like the McCloud-Pit, NFFR and other basins with substantial water storage useable for generation, the Mokelumne River system’s MW duration curves reflect an underlying pattern in which generation is cycled over the course of a week, reaching highest levels during the peak load hours of the day (especially weekdays), and dropping to minimum levels in off-peak hours, especially in early

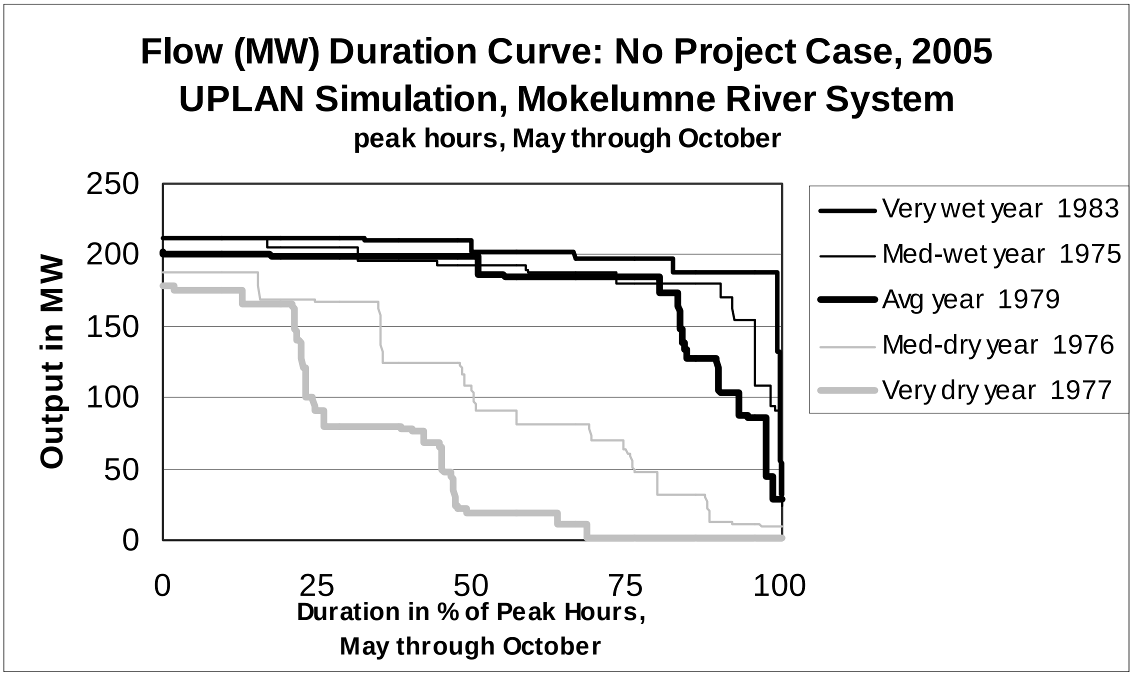

Figure C-15. Mokelumne River System Hourly MW Duration in Summer, Peak Hours

No Project Case, comparing five hydro years all projected for 2005

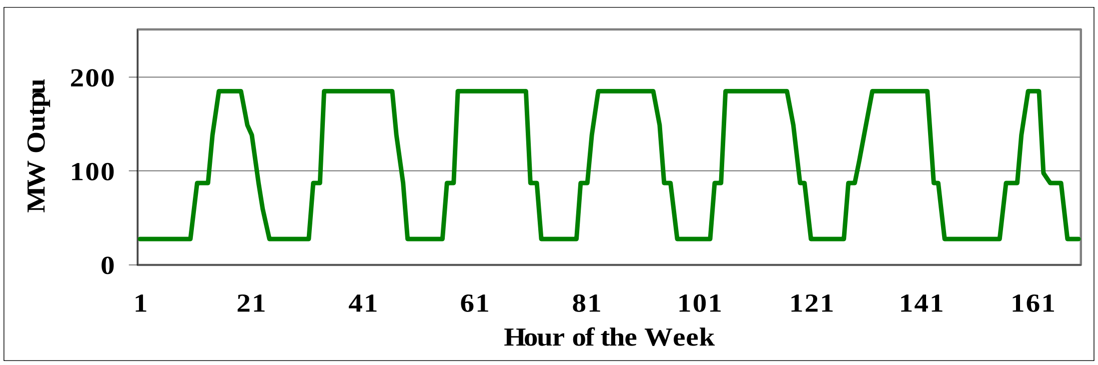

Figure C-16. Mokelumne System Chronological MW Output, Week of July 24, 2005

UPLAN simulation, No Project Case, hydro year 1979 (average conditions)

morning. Thus for an average hydro year 1979 (perhaps slightly wetter than average for this particular basin), generation projected over a mid-summer week demonstrates a pattern (Figure C-16) similar to that shown earlier for the Pit McCloud system. High generation levels are attained for few more hours during the week (Figure C-16 vs. Figure C-7), and minimum generation levels reflect a higher percentage (if not MW) of run-of-river generation.

During off-peak hours with relatively low market prices, generation is reduced to lower, usually minimum levels, to preserve stored water for use during peak hours. When water is used to generate above minimum levels during off-peak periods this is generally because so much water is available from inflows and/or storage that the most economic option is to use it for generation even during off-peak hours. In the summer period, generation from the Mokelumne River system is projected to exceed minimum levels roughly 60% of the time in wet years, about one-third of the time in a typical "average" year, and only about 10% of the time in dry years (Figure C-17). This is slightly less frequently than projected for the NFFR system, and, in dry years, is also less frequently than projected for the McCloud-Pit system. This reflects little use of storage hydro for off-peak summer generation except in wet years, although the run-of-river generation would be continuing in off peak hours, as reflected in Figure C-16. In winter when storage would be filled, the projected frequency of off-peak generation exceeding the minimum level is even lower, except under the wettest of conditions.

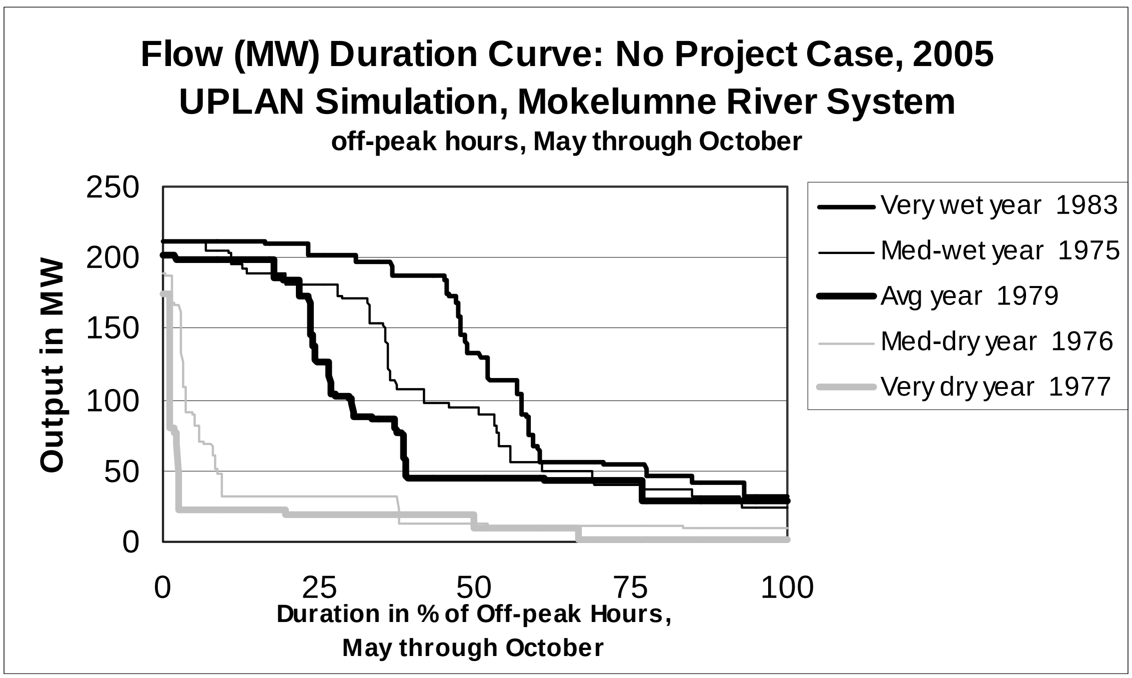

Figure C-17. Mokelumne System Hourly MW Duration in Summer, Off-Peak Hours

No Project Case, comparing five hydro years all projected for 2005

6.2.3 Effect of Four Divestiture Cases on Projected Hydro Generation Patterns

The preceding section illustrated how patterns of water use for hydroelectric generation vary among basins due to differences in hydrology and configuration of the hydroelectric system facilities. It especially illustrated how, under the Baseline and No Project Cases, water use for generation is greatly influenced by hydrologic conditions that vary greatly from year to year in California and the

WSCC. This Section analyses the effects of four different divestiture cases on hydroelectric operations projected for 2005.

The limited impact of the divestiture cases compared to the impact of hydrologic conditions reflects physical limitations, legal/contractual restrictions, informal agreements, and ownership by others of various in-basin facilities and water rights, all of which constrain how a future owner could rationally operate the hydroelectric facilities. On the other hand, variation of hydrology, system configuration and constraints from basin to basin gives hydroelectric facilities in some basins much greater potential for varying operations after divestiture, compared to other basins. As above, the following discussion focuses on the McCloud-Pit, NFFR and Mokelumne systems. These systems provide substantial amounts of generation and a range of potentials for altering operations in the future. All three received considerable attention in this study.

Example Divestiture Case Impacts on Hourly Generation: McCloud-Pit System

While the McCloud-Pit system is the largest contributor to Pacific Gas and Electric Company's hydroelectric system and has considerable storage, modeling and analysis indicate limited potential for variation of operations across the divestiture cases. This is because usable storage is not large relative to large water flows that persist into the summer more than in the other basins. While there is potential to time generation for the peak load hours on a daily basis, there is much less potential to store water or vary water use strategies on a longer term basis. Also, there are fewer water use agreements and practices considered subject to variation in the future, compared to some of the other basins.

The result is that across the four divestiture cases analyzed, there is little variation in projected frequency of achieving different MW output (or water release) levels. The impact of the divestiture cases is largest in summer (May-October), but even then it is small, for either wet (Figure C-18) or critically dry (Figure C-19) years. The main effects are a moderate reduction in generation under the Proposed Settlement Case due to assumed purchase of streamflows (no longer diverted for generation), and increased summer (but not winter) generation under The PowerMax Case (maximize profits) in wet years. The impact on projected frequency of maximum and minimum generation levels is very minor, mainly consisting of somewhat over 10% increase in frequency of reaching maximum generation levels under the PowerMax Case, in summers of wettest years.

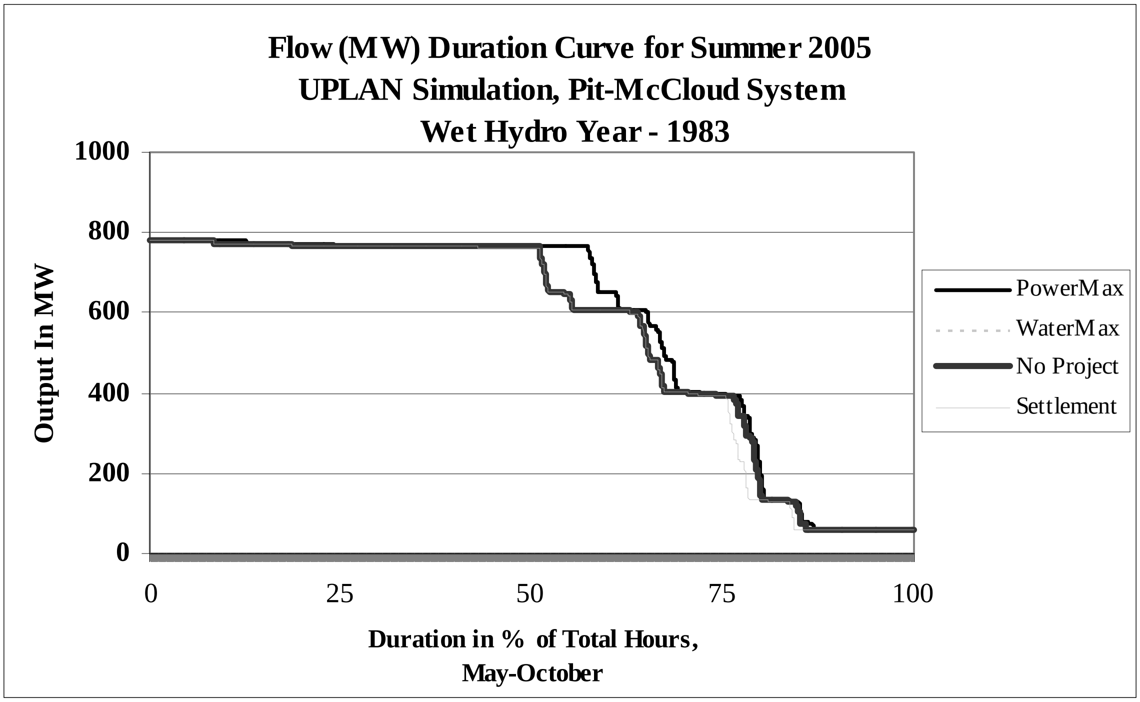

Figure C-18. McCloud-Pit System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Wet Hydro Conditions (1983)

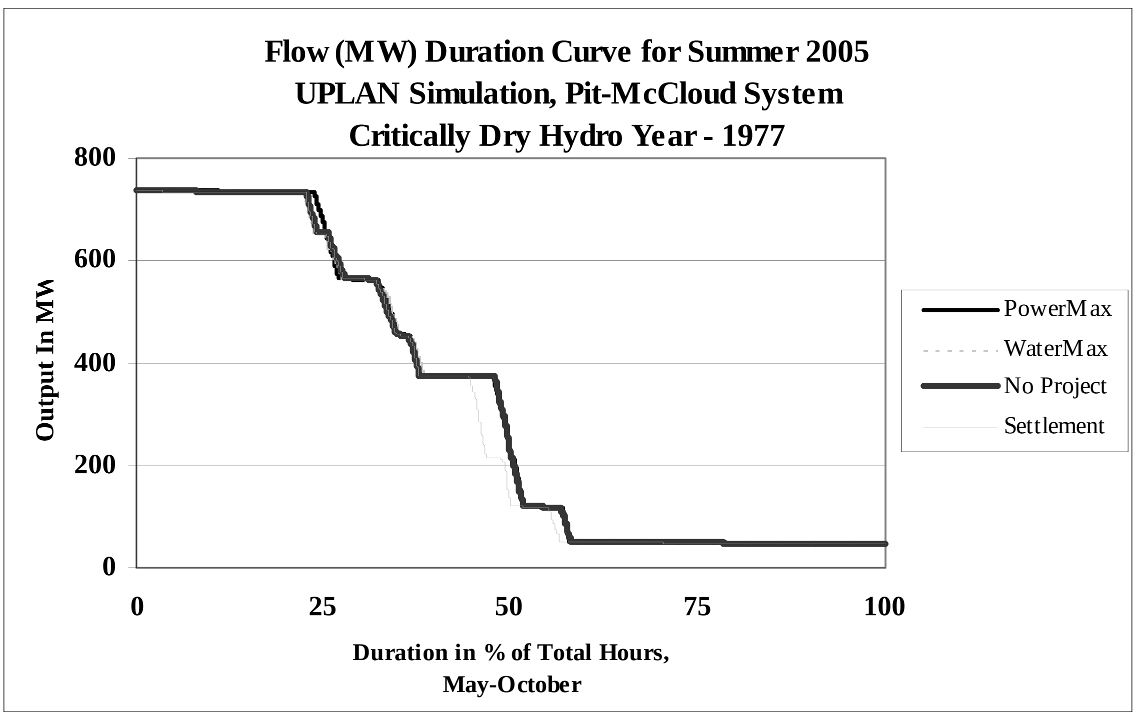

Figure C-19. McCloud-Pit System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Critically Dry Hydro Conditions (1977)

Example Divestiture Case Impacts on Hourly Generation: NFFR System.

Of all of the water basins and groups of hydroelectric facilities analyzed in this study, the North Fork Feather River (NFFR) system accounted for the greatest impact of divestiture cases on projected hydroelectric operations. This reflects the large amounts of both generation and storage, combined with considerable flexibility.

The purchase of streamflows assumed under the Proposed Settlement Case reduces water projected to be available for generation. This slightly reduces the projected frequency with which maximum generation levels are reached, mainly in the summer and under dry conditions. However, the biggest impacts come from the PowerMax and the WaterMax Cases.

The PowerMax Case represents heightened efforts to time generation for periods of highest market prices, observing legally binding water use constraints but not the informal constraints that were assumed to continue under the No Project Case. For winter, the result is lower generation levels and lower frequency of high generation hours, somewhat under dry conditions (Figure C-20) but especially under wet conditions (Figure C-21). This represents keeping more water in storage for use in the summer. The impact on frequency of reaching maximum or minimum generation levels is modest, mainly a decrease in projected frequency of reaching maximum MW output levels.

In summer, the PowerMax Case results in higher generation levels using stored water, taking advantage of peak loads and high market prices. Compared to the No Project Case, the projected frequency of reaching maximum output levels more than doubles under the driest conditions (Figure C-22), and increases slightly under the wettest conditions, where the frequency would already be high (Figure C-23). The PowerMax Case has little impact on the projected frequency of dropping to minimum generation levels in summer under the driest conditions, moderately reduces the frequency under average water conditions (not shown), and reduces the frequency to zero under wet conditions.

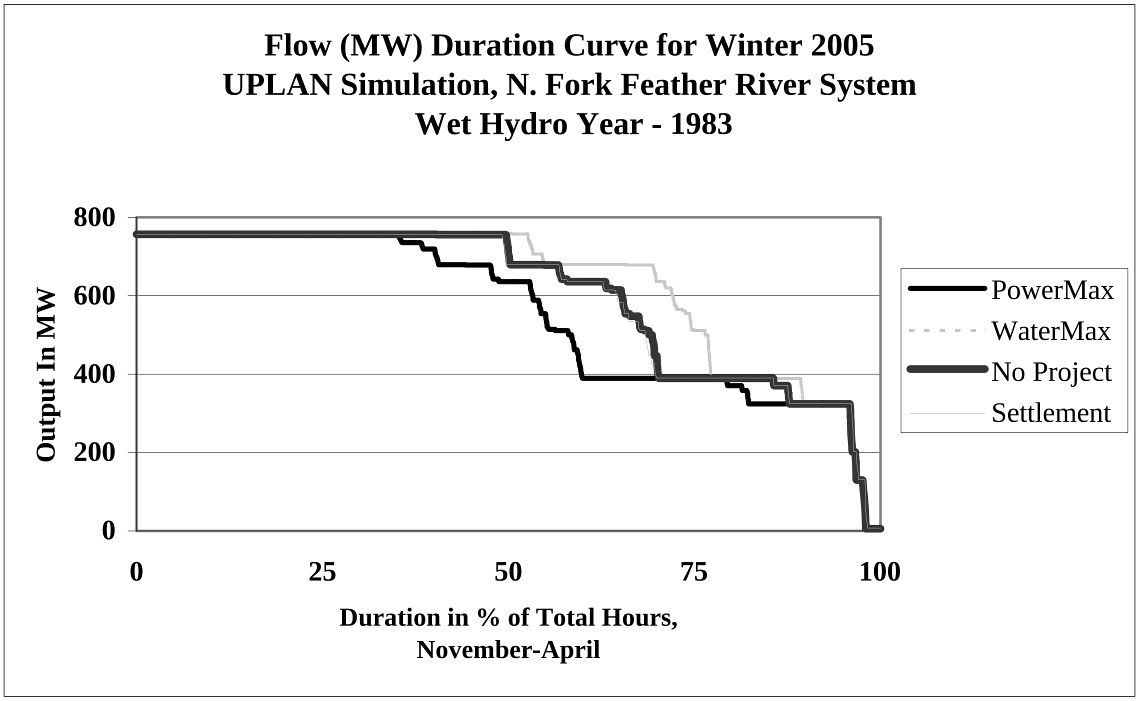

Figure C-20. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Winter, Wet Hydro Conditions (1983)

The WaterMax Case represents revised commercial priorities that emphasize reliability and profitability of water deliveries. It had a great impact on projections for the NFFR system, with its large storage and flexibility. In winter under wet conditions, the revised monthly schedules of water use for generation result in increased generation and especially, increased frequency of attaining high and maximum generation levels (Figure C-20). This presumably reflects holding reservoirs at higher levels going into wet winters, increasing the potential of both spills and high generation in winter/spring. In the summers under wet conditions, the WaterMax Case entails lower projected generation levels, and in particular, a substantial increase in projected frequency of low and even minimum generation levels (Figure C-21). These results are less pronounced under average (rather than wet) water conditions.

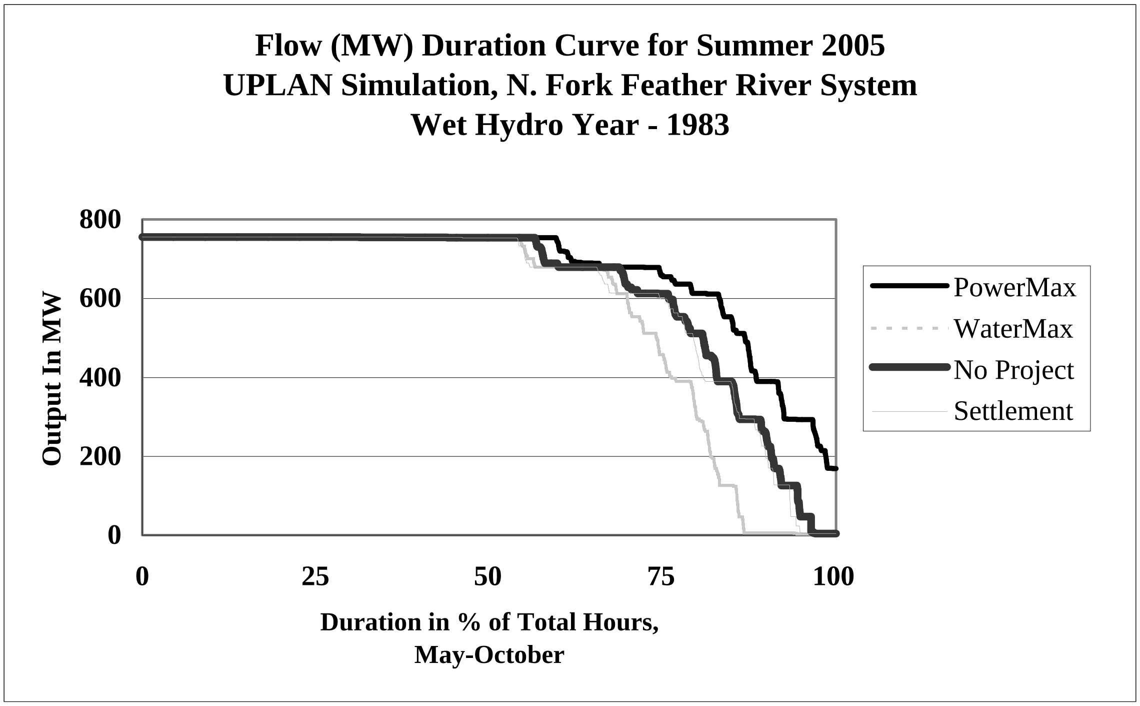

Figure C-21. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Summer, Wet Hydro Conditions (1983)

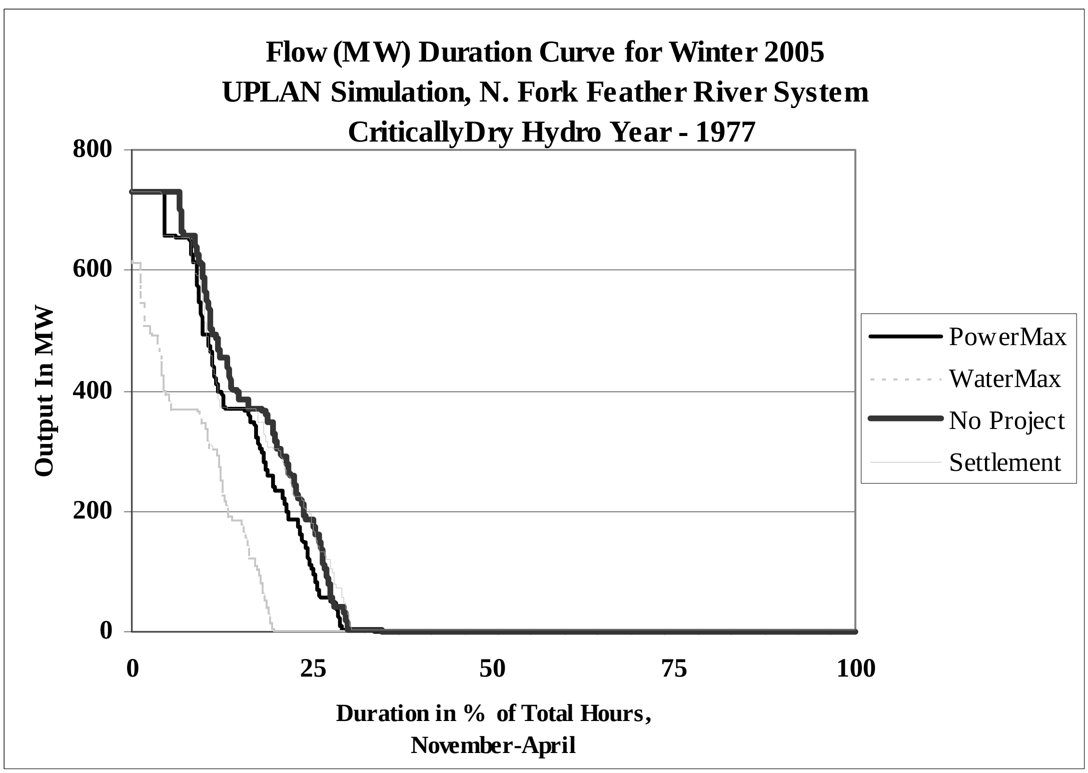

Figure C-22. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Winter, Critically Dry Hydro Conditions (1977)

Under critically dry conditions the impact of the WaterMax Case is quite different. Winter generation levels are decreased, reflecting extreme drawdown of reservoirs the previous year, so that early winter generation is very low. Minimum generation levels are projected to occur more frequently in the winter, and maximum generation levels are not even projected to be reached, as water is added to the depleted reservoirs (Figure C-22). However, under the driest conditions (Figure C-23) and also under somewhat less dry conditions (not shown), the WaterMax Case is projected to result in much higher summer generation levels than the No Project Case, as water is withdrawn from reservoirs for water deliveries (also used for generation). This leaves low water levels in reservoirs and consequent low end-of year (“winter”) generation. Under the WaterMax Case, maximum generation levels are projected to be reached about 25% of the time in summer under critically dry conditions, much more often than under the No Project Case. Minimum generation levels are projected to occur less than (instead of more than) half of the time.

Example Divestiture Case Impacts on Hourly Generation: Mokelumne System

Modeling of the Mokelumne River system powerhouses shows a slightly greater impact of the divestiture cases than for the McCloud-Pit system, but less than for the NFFR system. Greater water use restrictions and lesser amounts of storage help account for this lower response, reducing the flexibility for altering operations under different future conditions. In addition, the proposed Settlement Agreement does not identify any streamflows potentially to be purchased from this system. A separate relicensing settlement agreement is pending for Project 137, but this agreement is not reflected in the modeling presented here. The greatest divestiture case impact on modeled operations for the Mokelumne River powerhouses was a slight elevation of hourly generation levels projected for the winter (especially, end-of-year months) under the PowerMax Case (maximize profits, only binding constraints remain). This is illustrated for an average year (Figure C-24), but also occurred for other years. It results in a slightly increased frequency of attaining maximum generation levels and a slightly decreased frequency of falling to minimum generation levels, relative to the No Project Case. In addition, the minimum and maximum generation levels are themselves increased due to slightly higher run-of-river generation. The divestiture cases have very little impact on projected summer generation patterns for the Mokelumne River system, as illustrated for an average year in Figure C-25.

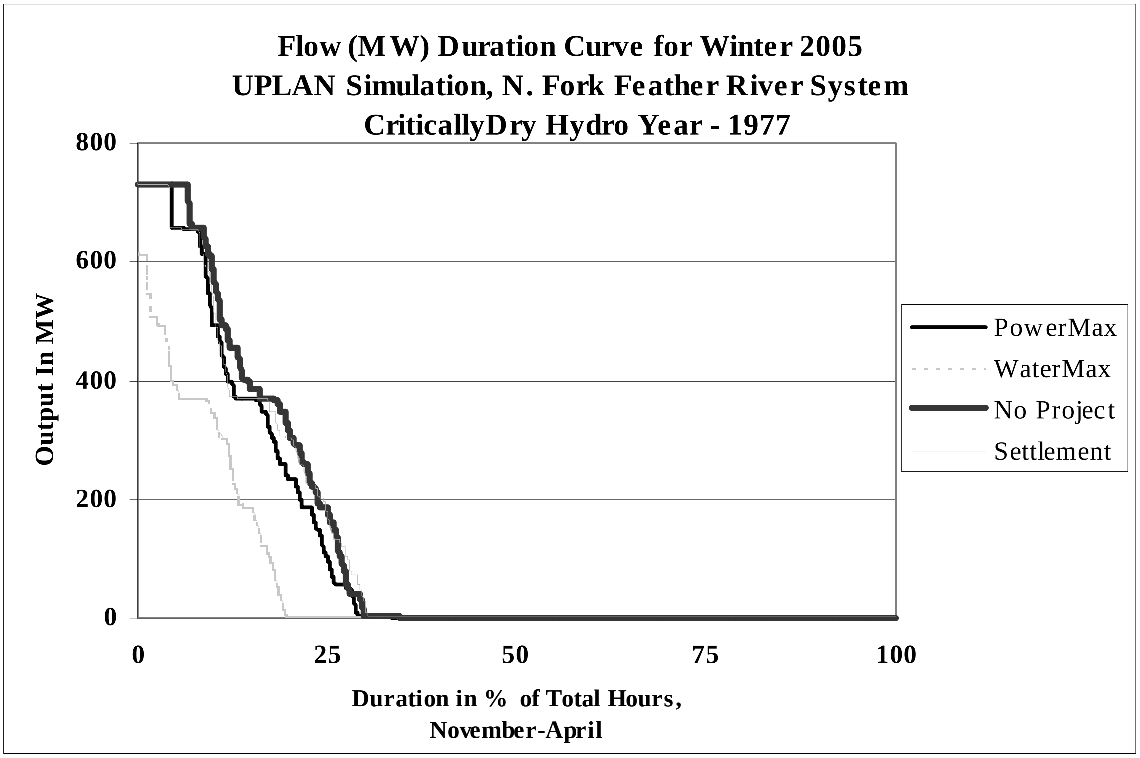

Figure C-23. NFFR: Effect of Divestiture Cases on Hourly MW Duration in Summer 2005, Critically Dry Hydro Conditions (1977)

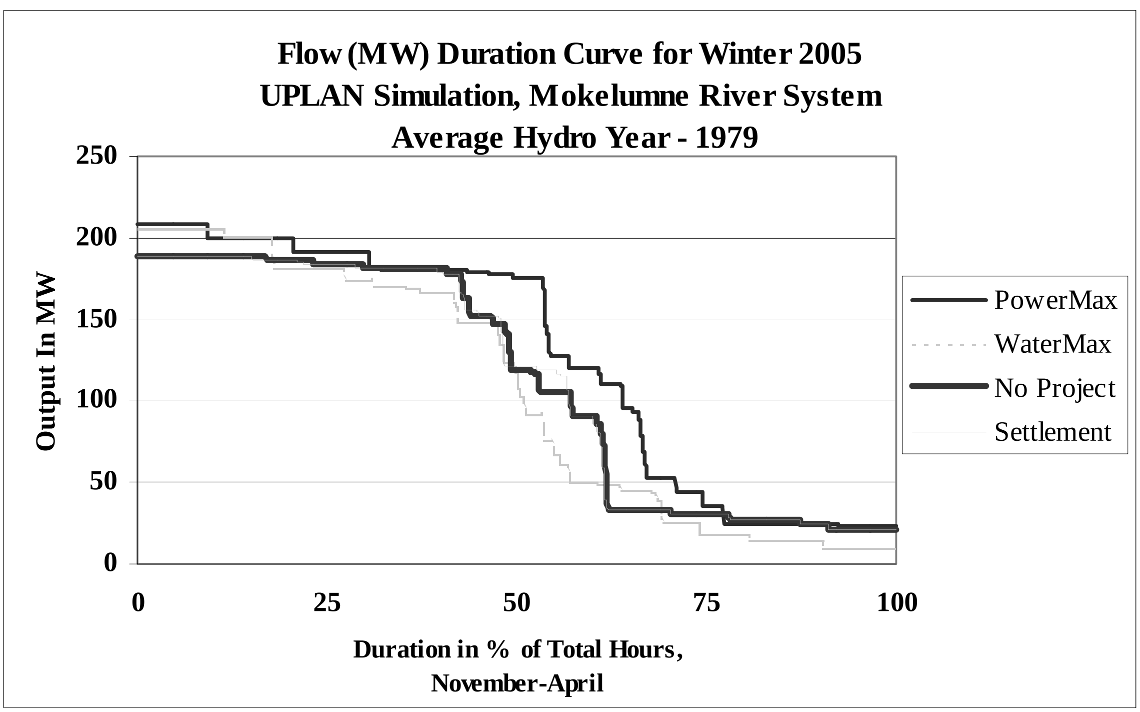

Figure C-24. Mokelumne System: Effect of Divestiture Cases on Hourly MW Duration in Winter, Average Hydro Conditions (1979)

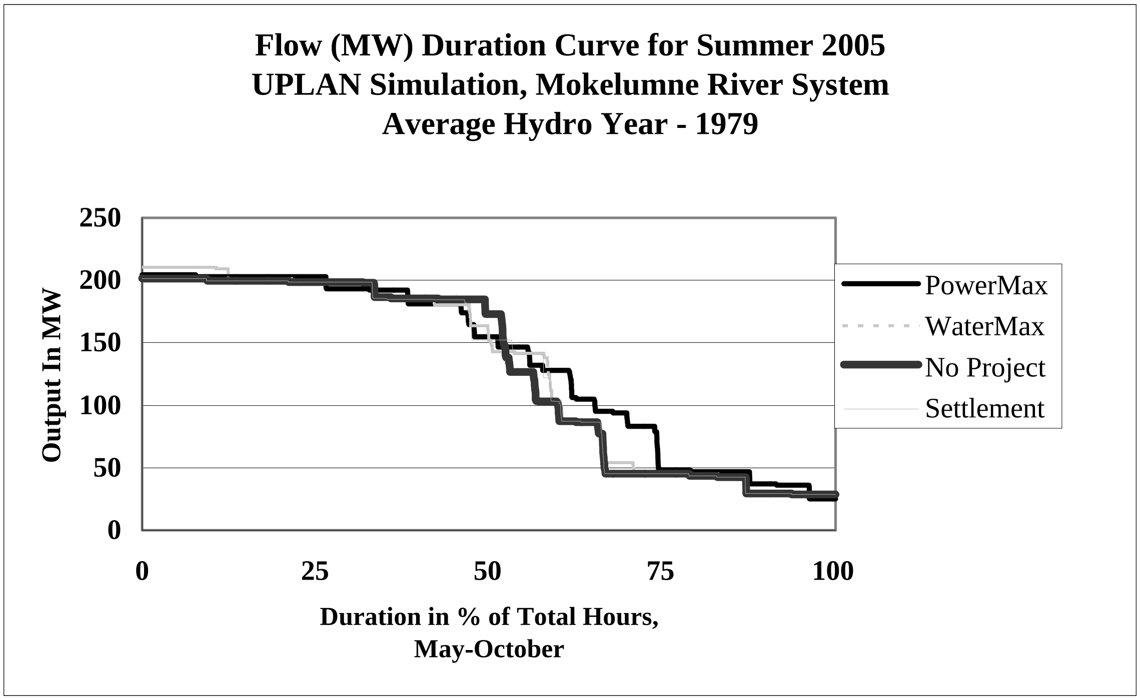

Figure C-25. Mokelumne System: Effect of Divestiture Cases on Hourly MW Duration in Summer, Average Hydro Conditions (1979)

Example Divestiture Case Impacts on Hourly Generation: Chili Bar

Pacific Gas and Electric Co. currently operates Chili Bar under an informal agreement with the commercial rafting operators. Pacific Gas and Electric Company notifies the rafting operators when it will not be meeting specified release targets during the rafting season. These targets generally call for power generation to ramp up starting by 9 AM, and for weekend releases similar to weekday releases. This operation requires coordination with the Sacramento Municipal Utility District to provide sufficient water from upstream storage.

In modeling the Pacific Gas and Electric Company hydropower system after divestiture, a reasonable expectation is that a new owner might not honor such an agreement, and instead would operate to maximize power revenues. With such a management objective, the new owners generally would operate to meet summertime peak loads, which occur in the afternoon and early evening. Thus, releases would occur later in the day, and at substantially lower levels during the weekends. The PowerMax Case was modeled based on this presumption.

Exhibit C-4 shows expected typical hourly Chili Bar operations for the months of July and August for weekdays and weekends under the PowerMax Case assumptions. Six different water-year type conditions that range from critically dry (1977) to extremely wet (1983) are shown. Note that under all but the wettest conditions, the weekend flows never top 1,200 cfs before noon in July or August.

6.2.4 Market Clearing Prices – Effect of Hydro Conditions

Hydroelectric generation plays a substantial role in overall power supply not only in California, but also across the WSCC. The great year to year variations in precipitation, runoff and resulting hydroelectric generation have a large impact on western power markets. In wet years low-cost energy from hydroelectric generation is abundant in the spring during runoff and persists at high levels into the summer. In dry years when less hydroelectric generation is available, especially into the summer, higher cost thermal generation sources must be called upon more frequently, driving up market prices.

California imports considerable amounts of electricity from other parts of the WSCC, including considerable hydroelectric generation from the Pacific Northwest. Generally a wet or dry hydro year in northern California where the Pacific Gas and Electric Company hydroelectric plants are located corresponds to a wet or dry year in the Pacific Northwest as well. Thus, a dry hydro year as modeled and evaluated in this study typically means high market prices in northern California not only because of low levels of hydroelectric generation in California, but because of low levels of hydroelectric generation across the WSCC.

This study considered a large range of hydro conditions, represented by 24 different historical years of data. In the UPLAN modeling, this range of conditions translated into a range of market clearing prices (MCPs) projected for 2005 in northern California (Figure C-26). Great variation among the 24 sets of water conditions produced considerable variation in MCP projected for the northern California pricing zone. The annual average (all-hour) prices differed by just over \$10/MWh (about 25%) between the wettest and driest of the historical hydro conditions simulated, and the average price for on-peak hours in August (over 300 hours altogether) differed by almost \$20/MWh, or over 30%. The price difference between MCP projected for more typical wet versus dry years are about \$5/MWh for all annual hours, and about \$10/MWh for the average peak hour prices in August. The lowest MCPs of the year, typically experienced in the spring when hydroelectric generation is high and loads are low, vary less across different hydro conditions On the other hand, the highest MCPs of the year, during summer peak load periods when hydro generation is more limited, vary about \$20/MWh between wettest and driest conditions.

Peak load hours give rise not only to the highest MCPs but also the greatest differences between wet versus dry conditions. The highest MCPs occur during on-peak summer hours (weekdays, 6AM to 10 PM) with high air conditioning loads, and this is also when MCPs are projected to vary the most across different hydro conditions (Figure C-27). The association of critically dry hydro conditions with great elevation of the very highest summer MCPs especially stands out on the left side of Figure C-27. However, wet versus dry hydro conditions are projected to make almost as great a difference in the peak hour MCPs during the winter (Figure C-28). It would be expected that storage-based hydro generation would have the greatest impact on peak (versus off-peak) MCPs, since this generation would generally be timed to coincide with peak loads.

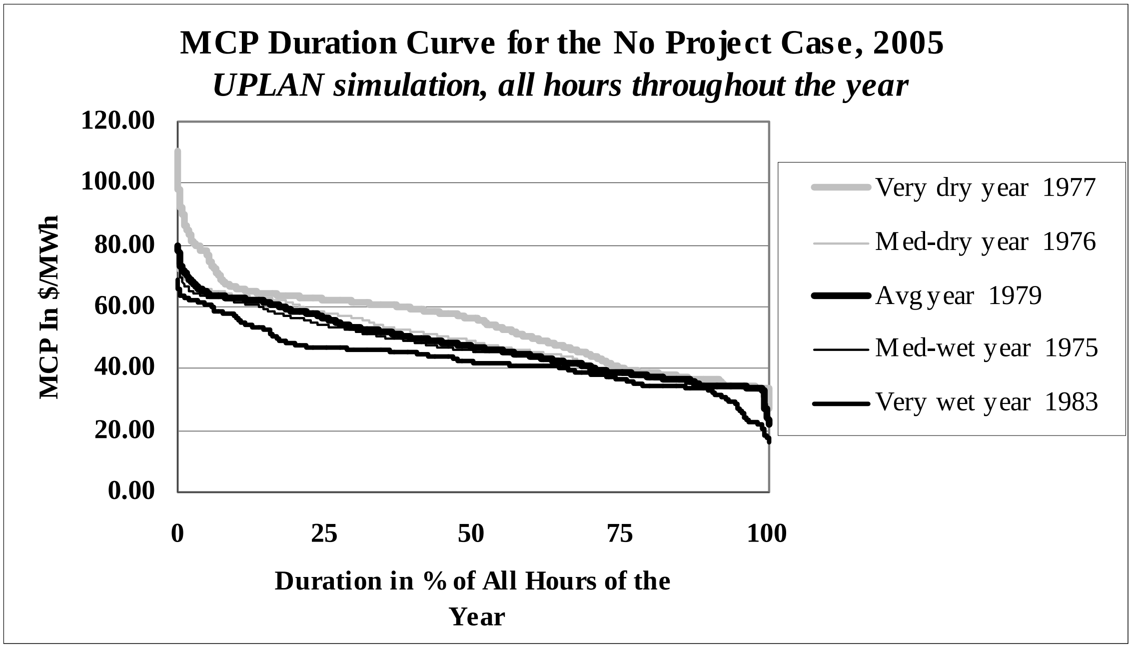

Figure C-26. Projected All Year Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions (For 2005, in year 2000$)

During off-peak hours, dry versus wet conditions have less of an impact on projected MCPs for northern California, especially in the winter (Figure C-29). In summer, differences in hydro conditions are projected to have a larger impact on off-peak MCPs, especially the highest off-peak MCPs of the summer (Figure C-30). Then, the difference between wettest and driest conditions is roughly $10/MWh. These highest off-peak MCPs would generally occur in mid to late summer, when water for generation is scarce in dry years.

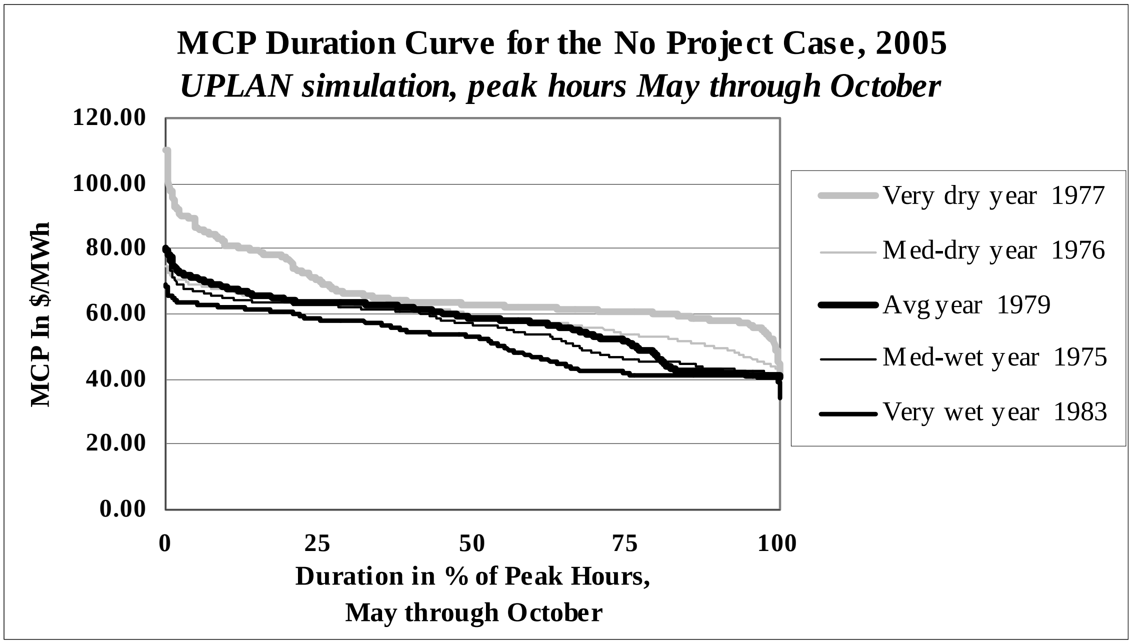

Figure C-27. Projected Summer On-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

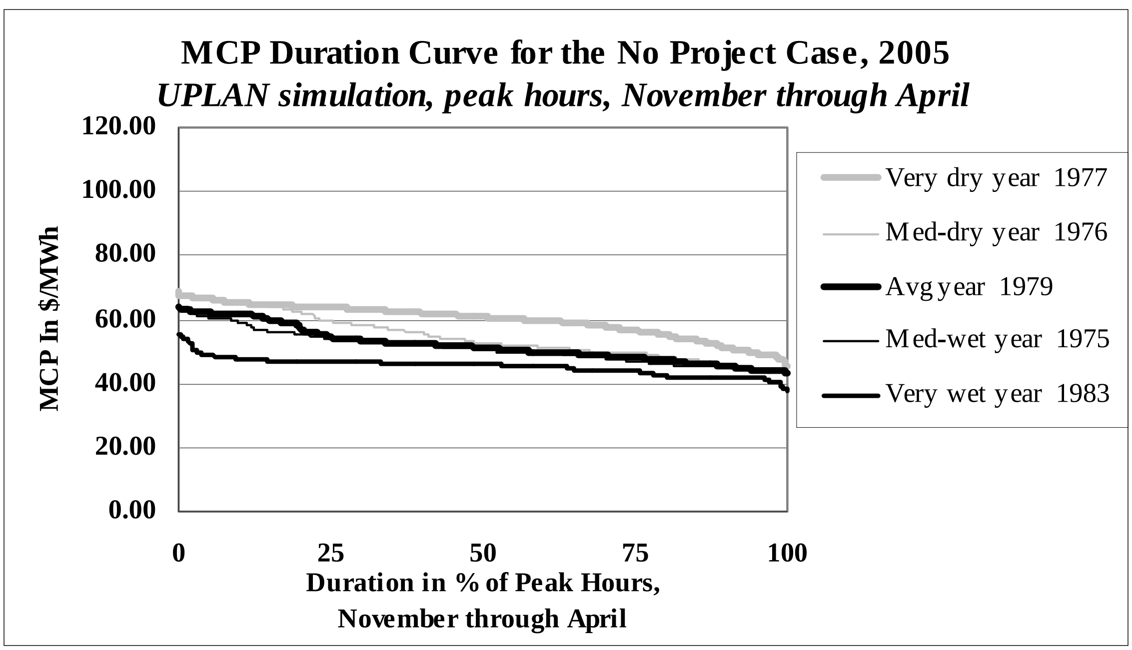

Figure C-28. Projected Winter On-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions ***(For 2005, in year 2000 $)***

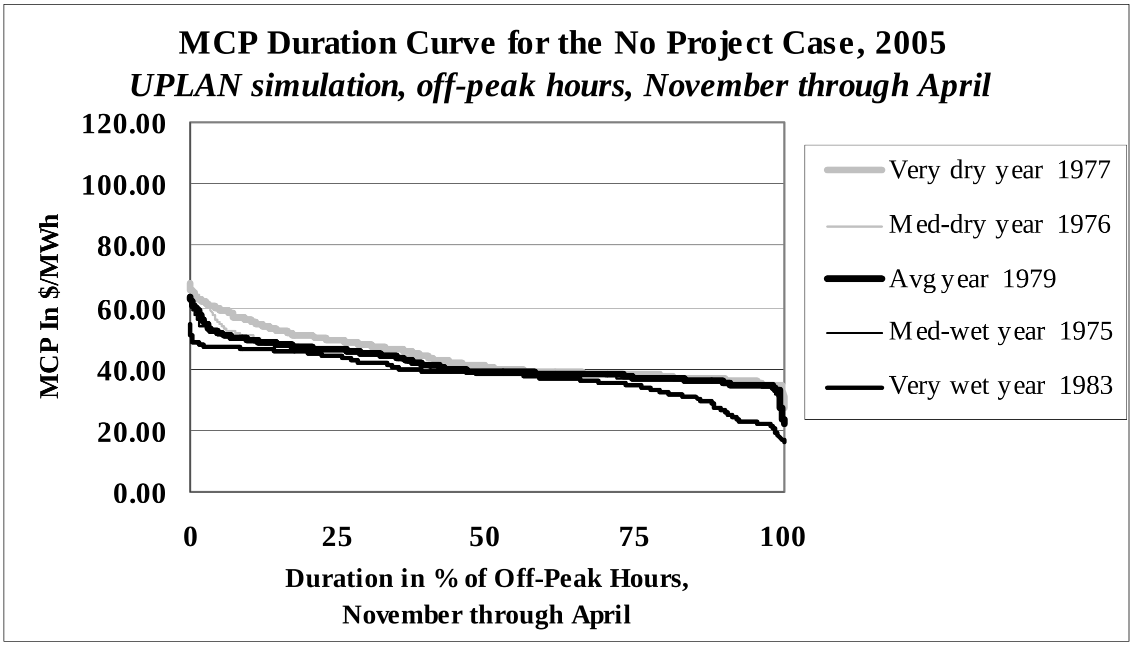

Figure C-29. Projected Winter Off-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions *(For 2005, in year 2000 $)*

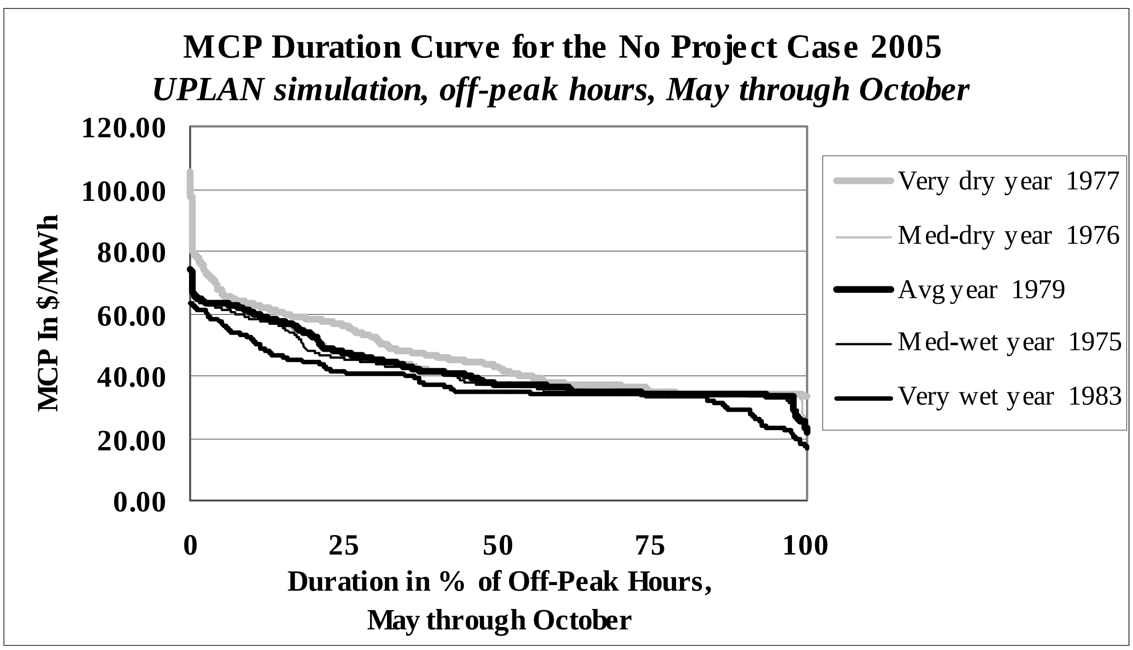

Figure C-30. Projected Summer Off-Peak Market Prices for Electric Energy in Northern California, Impact of Hydro Conditions *(For 2005, in year 2000 $)*

6.2.5 Market Clearing Prices – Effect of Divestiture Cases

For each divestiture case and each hydro year simulated, UPLAN projected hourly market clearing prices for each pricing zone (defined by transmission constraints) in the WSCC. With the exception of a very few powerhouses in the central California pricing zone, all Pacific Gas and Electric Company hydro facilities in question are in the northern California zone. UPLAN's MCP projections were used iteratively with runs of WRMI's OASIS model to develop optimized month to month schedules of water use for electric generation under the different divestiture cases and hydrologic conditions. UPLAN incorporated these schedules as constraints in simulating WSCC power markets and generator operations on an hourly basis.

As noted above, great variation among the 24 sets of water conditions produced considerable variation in MCP projected for the northern California pricing zone. In contrast, for any one set of hydro conditions, the difference in MCP across the four different divestiture cases analyzed was very small, generally in the range of 0.1% to 0.3% for annual average prices and somewhat less than twice that for August peak prices. Figure C-31 shows the MCP distribution for summer during a critically dry year (1977), and Figure C-32 shows the same distribution for an "average" year (1979). The similarity among the cases is evident from these charts.

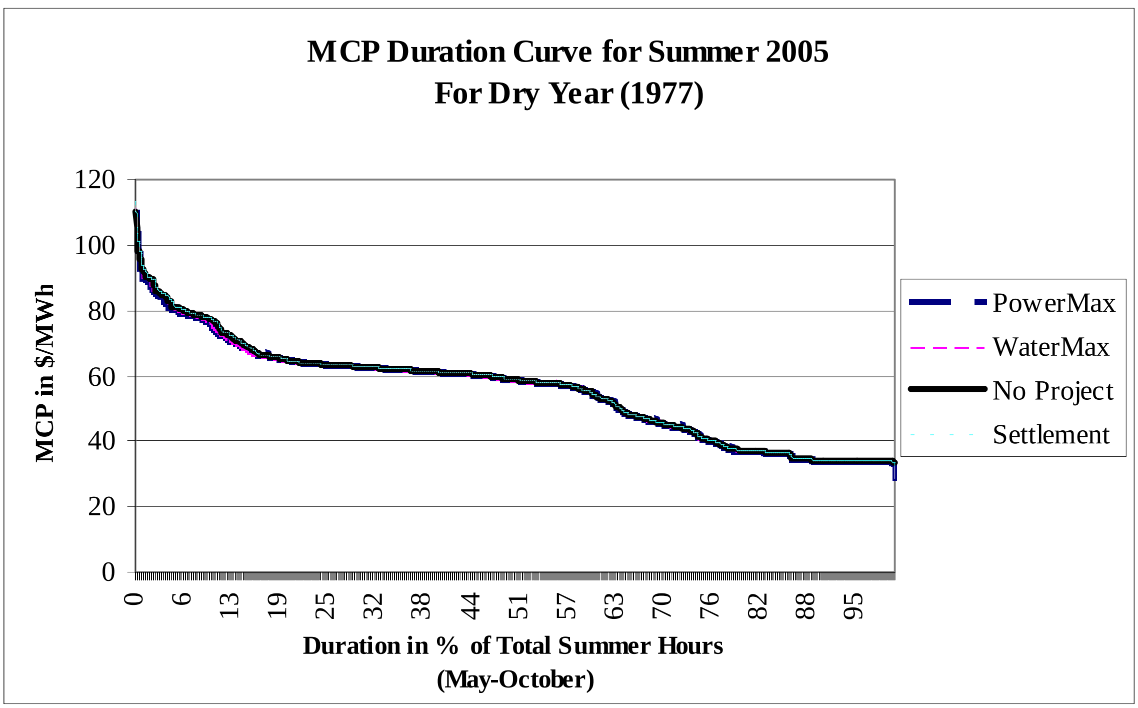

Figure C-31. Projected Summer Market Prices for Electric Energy in Northern California, Critically Dry Conditions, 1977 ***(For 2005, in year 2000 $)***

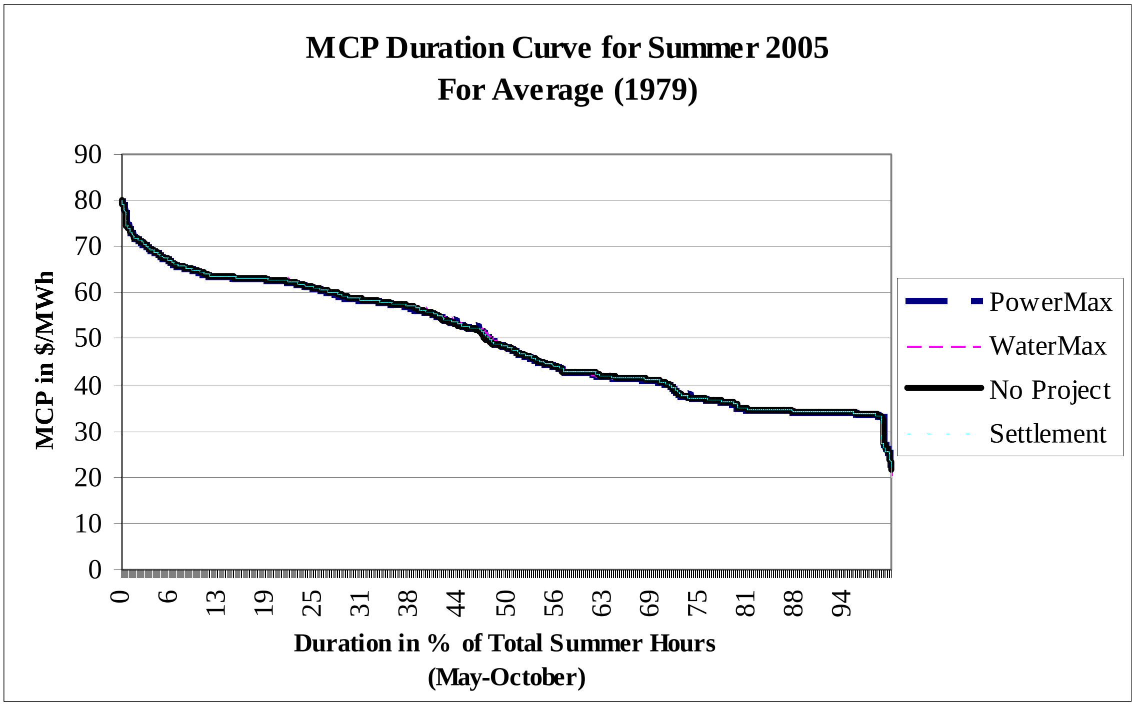

Figure C-32. Projected Summer Market Prices for Electric Energy in Northern California, Average Conditions, 1979 ***(For 2005, in year 2000 $)***

Occasionally, a greater difference was produced across divestiture cases. The greatest observed differential was for peak hour prices in August under 1977 hydro conditions, the driest of the 24 hydro years analyzed. Here, the WaterMax Case made substantially more water available for generation in mid-summer for the NFFR system while, simultaneously, the Proposed Settlement Case significantly (not greatly) reduced water available for generation, to maintain streamflows. These opposite impacts produced a 2.2% difference in projected on-peak MCPs for northern California in that month, between these two divestiture cases (simulated for year 2005). However, for the entire simulated year, under critically dry 1977 hydro conditions, the difference in yearly average on-peak MCP was only 0.35% between these two cases.

There are three basic reasons why different divestiture cases analyzed have a limited impact on projected MCP for northern California.

- Although the Pacific Gas and Electric Company hydroelectric system is large and makes a substantial contribution to electricity supply in northern California, most of the supply comes from other sources, including those outside of California.
- As noted previously, the extent to which operations of the Pacific Gas and Electric Company hydroelectric facilities could be varied by future owners is limited by physical conditions regarding water supply and configuration of the facilities, by various agreements and regulations constraining water use, and by other parties' ownership of water rights and/or water facilities (including powerhouses) in the basins involved.

- Under all divestiture cases modeled it is assumed that future owners will operate the facilities to maximize the coincidence of whatever generation is available with highest electric loads and prices, within the applicable physical, legal and other constraints.

The pattern of MCP differences across the four divestiture cases that were modeled is illustrated by the monthly average prices shown in Table C-14. Average prices are shown both for all hours of each month and for peak hours only, averaged over all 24 hydro years that were simulated. The prices are lowest in spring due to low electric loads and abundance of water for hydroelectric generation. Prices (especially peak prices) rise dramatically in mid-summer as loads rise and water supply dwindles, then drop in the fall. Overall, the prices in the second half of the year (July and later) are higher than those in the earlier half, making it worthwhile to store water for generation in the last half of the year, where possible.

The PowerMax Case assumes more aggressive maximization of profits from electric generation, by discontinuing non-binding water use constraints and saving more water for generation in the last half of the year (especially July through fall) when prices are high. This results in very minor increases in projected MCP over much of the spring (relative to the No Project Case), followed by MCP declines (also very minor) in summer-fall. This modest trend can be seen in both all-hours monthly average prices and in on-peak monthly average prices. When averaged over all 24 hydro years, the WaterMax Case, "water deliveries", tends to reverse this trend.[36] Averaged over 24 hydro years simulated, this case results in more water running through the turbines during the first half of the year in certain watersheds, and less in late summer and especially in fall, after summer water deliveries have been made. The Proposed Settlement Case removes some water from generators to enhance natural streamflows, and so results in a slight increase in MCP across all months.

Under wet hydro conditions (hydro year 1983), projected MCPs are lower due to greater amounts of low-cost hydroelectric generation, and the price rise in the summer is softened by the continued availability of water (Table C-15). The PowerMax Case has the same general effect on projected MCP for this single hydro year as for all 24 years combined. That is, more water is held in storage during spring runoff, during which time the projected MCP is very slightly higher than under the No Project Case. Then, in the latter half of the year with its higher market prices, hydro generation is increased relative to the No Project Case, and the MCP drops very slightly. The WaterMax Case (water deliveries) also has a similar effect on projected MCP for this single wet year as for all 24 hydro years averaged. More water is run through the turbines during spring runoff, slightly lowering projected MCP. By the fall, less water (and hydro generation) is available and projected MCP rise slightly above the No Project Case level. Finally, the Proposed Settlement

36 An important aspect to keep in mind about the WaterMax Case, as discussed in Section 3.2.3, is that it is highly improbable that all of the river basins that might be bought by entities with a water supply objective actually would be purchased with this purpose in mind. For this reason, no conclusions can be drawn about how this scenario might affect MCPs.

Case again has the effect of making slightly less water available (diverted) for generation, producing an MCP slightly higher than under the No Project Case, for all months under these wet (1983) hydro conditions.

Table C-14

Projected Northern California MCP for 2005, Average Over 24 Hydro Years

Monthly Average MCP, Hydro Years 1975-1998 Combined
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	47.99	48.04	1.001	47.97	0.999	48.01	1.000
2	45.95	45.96	1.000	45.94	1.000	45.97	1.000
3	42.87	42.91	1.001	42.83	0.999	42.89	1.000
4	43.95	43.97	1.001	43.90	0.999	43.97	1.000
5	40.35	40.19	0.996	40.31	0.999	40.39	1.001
6	42.86	42.89	1.001	42.75	0.998	42.91	1.001
7	53.78	53.64	0.997	53.79	1.000	53.86	1.001
8	55.93	55.80	0.998	55.98	1.001	55.97	1.001
9	52.10	52.04	0.999	52.11	1.000	52.14	1.001
10	48.93	48.84	0.998	49.11	1.004	48.97	1.001
11	48.97	48.90	0.999	49.13	1.003	49.00	1.001
12	48.79	48.81	1.000	48.88	1.002	48.81	1.000
Yr.	47.73	47.69	0.999	47.75	1.000	47.76	1.001

Monthly Avg.On-Peak MCP, Hydro Years 1975-1998 Combined
In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	53.87	53.96	1.002	53.85	1.000	53.90	1.001
2	50.99	50.97	1.000	50.97	1.000	51.00	1.000
3	47.38	47.41	1.001	47.35	0.999	47.40	1.000
4	49.72	49.76	1.001	49.67	0.999	49.74	1.000
5	45.03	44.68	0.992	44.98	0.999	45.07	1.001
6	48.44	48.49	1.001	48.28	0.997	48.52	1.002
7	63.57	63.43	0.998	63.55	1.000	63.66	1.001
8	66.53	66.40	0.998	66.52	1.000	66.58	1.001
9	61.41	61.39	1.000	61.42	1.000	61.45	1.001
10	56.78	56.68	0.998	57.09	1.005	56.85	1.001
11	56.11	56.06	0.999	56.34	1.004	56.14	1.001
12	55.09	55.16	1.001	55.25	1.003	55.13	1.001
Yr.	54.60	54.56	0.999	54.63	1.001	54.64	1.001

Table C-15

Projected Northern California MCP for 2005, Wet Hydro Year (1983)

Monthly Average MCP, Hydro Year 1983 (wet)

In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	44.11	44.21	1.002	44.15	1.001	44.21	1.002
2	41.83	41.95	1.003	41.88	1.001	41.97	1.003
3	37.76	38.24	1.013	37.57	0.995	37.69	0.998
4	38.53	38.73	1.005	38.50	0.999	38.57	1.001
5	36.13	36.18	1.001	36.15	1.000	36.19	1.002
6	37.40	37.13	0.993	37.39	1.000	37.49	1.002
7	48.10	48.09	1.000	48.09	1.000	48.11	1.000
8	50.25	50.14	0.998	50.55	1.006	50.28	1.001
9	47.95	47.82	0.997	48.02	1.001	48.05	1.002
10	44.74	44.72	0.999	44.84	1.002	44.79	1.001
11	43.23	43.18	0.999	43.32	1.002	43.24	1.000
12	42.69	42.59	0.998	42.71	1.001	42.71	1.001
Yr.	42.75	42.77	1.000	42.78	1.001	42.79	1.001

Monthly Average On-Peak MCP, Hydro Year 1983 (wet)

In $/MWh, UPLAN Projection for year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	47.46	47.57	1.002	47.46	1.000	47.55	1.002
2	46.31	46.31	1.000	46.25	0.999	46.31	1.000
3	42.81	43.29	1.011	42.78	0.999	42.82	1.000
4	41.99	41.98	1.000	41.97	1.000	41.98	1.000
5	40.99	40.95	0.999	40.99	1.000	40.99	1.000
6	41.97	41.97	1.000	41.97	1.000	41.97	1.000
7	56.97	56.94	0.999	56.99	1.000	56.98	1.000
8	59.34	59.25	0.998	59.64	1.005	59.41	1.001
9	56.41	56.37	0.999	56.45	1.001	56.48	1.001
10	51.32	51.28	0.999	51.41	1.002	51.37	1.001
11	47.59	47.51	0.998	47.63	1.001	47.60	1.000
12	46.25	46.28	1.001	46.26	1.000	46.26	1.000
Yr.	48.30	48.33	1.001	48.34	1.001	48.33	1.001

Very different MCP results are produced under year 1977 hydro conditions, the driest over the 24 hydro years simulated (Table C-16). First, with low hydroelectric generation across the west, projected MCP for 2005 are much higher, and they peak dramatically in the mid-summer (refer to Table C-16 and the left side of Figure C-27). In these stressed electricity supply circumstances, the PowerMax Case reduces projected mid-summer prices (especially on-peak) by making more water available for generation in mid-summer (and less in the fall). However, the WaterMax Case has a greater impact, by making even more water available for generation in mid-summer (and even less available in the fall), mainly through changes in the NFFR system operations. This leads to average and on-peak MCP being 1-1.5% percent lower than under the No Project Case in June-

August. For most hydro conditions simulated, the Proposed Settlement Case produces slight increases in projected MCP due to reduced water diversions for generation, but in the critically dry summer conditions under hydro year 1977, the Proposed Settlement Case has a greater effect, increasing MCP by about 0.5% above the No Project Case level. It is these opposite effects of the WaterMax Case (water deliveries) making more water available for generation in the dry summer and the Proposed Settlement Case making less water available that produces the greatest observed MCP differential among divestiture cases, 2.2% for on-peak prices in August under 1977 hydro conditions. For other times of the year and under other hydro conditions, the MCP impact across the different cases is much less, as noted earlier.

Table C-16

Projected Northern California MCP for 2005, Critically Dry Hydro Year (1977)

Monthly Average MCP, Hydro Year 1977 (dry)

In $/MWh, UPLAN Projection year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	51.06	51.08	1.000	50.93	0.997	51.05	1.000
2	51.17	51.17	1.000	51.16	1.000	51.19	1.000
3	47.66	47.65	1.000	47.70	1.001	47.69	1.001
4	53.67	53.63	0.999	53.64	1.000	53.69	1.000
5	49.34	49.40	1.001	49.33	1.000	49.36	1.000
6	51.56	51.50	0.999	51.16	0.992	51.61	1.001
7	62.90	62.44	0.993	62.25	0.990	63.18	1.004
8	63.33	62.53	0.987	62.45	0.986	63.55	1.003
9	54.46	54.63	1.003	54.36	0.998	54.47	1.000
10	52.55	52.67	1.002	52.72	1.003	52.56	1.000
11	53.30	53.23	0.999	53.63	1.006	53.37	1.001
12	51.54	51.43	0.998	51.93	1.008	51.54	1.000
Yr.	53.57	53.47	0.998	53.46	0.998	53.63	1.001

Monthly Average On-Peak MCP, Hydro Year 1977 (dry)

In $/MWh, UPLANr Projection for M21year 2005

Mo.	No Project, (NP)	The PowerMax Case (PM)	PM vs. NP	The WaterMax Case (WM)	WM vs. NP	Settlement	Settlement vs. NP
1	58.89	58.97	1.001	58.66	0.996	58.84	0.999
2	59.46	59.45	1.000	59.43	1.000	59.48	1.000
3	54.56	54.54	1.000	54.62	1.001	54.59	1.001
4	63.41	63.39	1.000	63.40	1.000	63.43	1.000
5	58.61	58.73	1.002	58.61	1.000	58.64	1.000
6	60.57	60.47	0.998	59.93	0.989	60.62	1.001
7	76.45	75.73	0.991	75.69	0.990	76.96	1.007
8	77.72	76.47	0.984	76.44	0.984	78.14	1.005
9	64.33	64.63	1.005	64.20	0.998	64.33	1.000
10	61.68	61.93	1.004	62.08	1.007	61.70	1.000
11	62.69	62.67	1.000	63.24	1.009	62.77	1.001
12	59.76	59.65	0.998	60.37	1.010	59.77	1.000
Yr.	63.20	63.07	0.998	63.07	0.998	63.29	1.002