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THE DYNAMIC ALTERNATIVE: AN INTEGRATED BASIS FOR COST RECOVERY

A Report to Multi State Process Participants
by
the Utah Parties

A. Introduction and Conclusions

Utah Parties submit the Dynamic Alternative for Multi State Process (MSP) consideration as a means of resolving the interjurisdictional cost allocation problems PacifiCorp has identified. We believe the Dynamic Alternative addresses the feeling some states have that Utah's fast growth is imposing costs on them unfairly, the PacifiCorp concern that states are "going their own ways" making the traditional approach to cost allocation unworkable, and other potential differences among the states on interjurisdictional cost allocation points which have arisen in the MSP.

Our analysis shows that traditional cost allocation is both flexible enough and capable enough to resolve the question posed by differing characteristics of jurisdictional growth, and can do so equitably and effectively; that the key example of differing state policies, direct access, can be handled within the framework of traditional cost allocation; and that the remaining interjurisdictional allocation concerns likewise can be resolved without the necessity of abandoning that approach.

Specifically, our conclusions thus far suggest:

- The allocation factors used traditionally do directly capture the cost allocation effect of differing rates of growth and can be altered constructively in view of changes in jurisdictional and system load characteristics;

- A wholesale jurisdiction would be beneficial for interjurisdictional cost allocation so long as PacifiCorp's utility operations are strongly influenced by wholesale market transactions but necessary if an hourly basis for cost allocation were to be adopted;

- Utah Parties may be willing to consider a hydro endowment.

- The effects of direct access permitted by one jurisdiction can be accommodated ("walled-off") using traditional cost allocation and rate case techniques;

- Washington's request for unique status within the system is a rate case prudence or used-and-useful issue rather than an interjurisdictional cost allocation one;

- Special retail contracts present an issue only in their interruptible form and this can be resolved within the traditional cost allocation framework; and

- Sale or purchase of service territory raises no problem uniquely difficult to resolve within the traditional cost allocation framework.

B. Elements of the Dynamic Alternative Examined

As we stated in our November 26, 2002 Memorandum which first set out the Dynamic Alternative,

> Our [Dynamic] alternative arises from several principles. First, we want to respect the integrity of the integrated system, and would do so by means of a method of apportioning costs for recovery from jurisdictions that is fair and consistent, to the extent practicable, with the planning and operation of the integrated system. Costs of providing service should be recovered from those who cause them to be incurred, to the extent cost causation can reasonably be determined. Because of the inherent difficulties in analyzing historical characteristics of cost incurrence, we believe the analysis should focus primarily on current cost causation characteristics. Moreover, given the complexities of applying different allocation factors to plant vintages, we also believe it is preferable to utilize consistent allocation methods for all plant. We believe that a more in-depth analysis of traditional cost causation factors will help identify and narrow a reasonable range of classification and allocation approaches, and will inform both negotiations and debates over the policy issues inherent in the ultimate classification and allocation decisions. We want to avoid unreasonable or inappropriate cost shifts, to promote rate stability and administrative ease, and to adopt procedures that are sustainable.

The following elements of the Dynamic Alternative, it will be recalled, were selected in response to the Oregon Preliminary Proposal to the MSP.

1. Classification and Allocation of System Production Costs

Our analysis of the job that load-based allocation factors currently do to shift jurisdictional revenue requirement to cost-causing jurisdictions, of the technical basis for classifying production costs as demand- or energy-related, and of stress factors to indicate the set of months for the capacity allocation factor, reveals no compelling reason to abandon the current 12-CP 75/25 system generation factor. At this point, a demonstratively preferable alternative is not apparent to us.

A. Load-based allocation factors capture changes in jurisdictional load characteristics.

In this section we address the MSP concern that relatively rapid growth in the Utah jurisdiction is inappropriately shifting costs to other jurisdictions, or, in other words, the concern that traditional interjurisdictional cost allocation does not properly apportion system costs to cost-causing jurisdictions. First, we show how the principal components of system cost-of-service vary among jurisdictions. Our examination of the relative proportions of cost-of-service components reveals interesting variations among jurisdictions, and offers a partial explanation for jurisdictional cost-of-service differences. We also examine whether load-based allocation factors respond to relative growth pressures by directing costs to the more rapidly growing jurisdiction. We are able to confirm that load-based allocation factors do apportion a larger share of system costs to rapidly growing jurisdictions.

(1) The emphasis of the MSP is on production costs. But another component of total system cost-of-service, distribution, is a surprising source of jurisdictional revenue requirement variation. Thus, despite lower production costs, a jurisdiction may have high overall costs.

Among the production, transmission, distribution, and overhead cost-of-service components, the MSP concern with varying jurisdictional growth rests on allocation of the production-cost component. A cost-of-service analysis that unbundles total system costs to show the relative proportions of the four components reveals how the proportions vary among the jurisdictions. Using actual results of operations (reported in the *Semi Annual Report* filed July 31, 2002) for the period April 2001 to March 2002, Utah Commission staff performed such a study. See Table 1 below. The results were presented to the MSP at the November 13, 2002 Las Vegas meeting. We are cognizant of PacifiCorp's observations there, and in a previous Utah technical conference, about the influence of the BPA credit in some states. But as we show below, with or without the BPA credit, the study correctly indicates each component's relative proportion of cost of service, and how these proportions vary among the state jurisdictions.

Table 1. Unbundled Cost of Service, April 2001 - March 2002.

Unbundled Function	Percent of COS	System	CA	OR	WA	WYP	UT	ID	WYU
Production	56.3%	$27.73	$31.11	$26.74	$25.80	$26.28	$30.85	$21.12	$26.33
Transmission	9.1%	$4.50	$4.45	$4.83	$4.38	$4.41	$4.43	$4.17	$3.87
Poles & Wires	27.7%	$13.63	$34.99	$17.25	$11.71	$8.53	$13.09	$8.89	$9.41
Customer	4.0%	$1.95	$3.47	$2.05	$2.04	$1.16	$2.26	$1.14	$1.34
Miscellaneous	2.9%	$1.41	$2.17	$3.14	$0.51	$0.59	$0.74	$0.90	$0.30
Total	100.0%	$49.22	$76.19	$54.01	$44.44	$40.97	$51.37	$36.23	$41.26

With embedded costs fully rolled-in, and overhead costs, including taxes, apportioned among the primary functions, the study shows that on a system basis production costs equal 56 percent of total cost of service. On a per MWh basis (using the MWh upon which allocation factors are based), production costs vary from a low of $21 in Idaho to a high of $31 in California and Utah. Oregon, Washington and Wyoming fall between $26 and $27. Utah's relative production cost responsibility for the 12-month period ending March 2002 was 15 percent greater than Oregon's and 20 percent greater than Washington's.

Transmission costs are but 9 percent of total cost of service, and vary among jurisdictions in a tight $4 to $5 per MWh range. At this point in the MSP, transmission cost allocation is not in dispute. Transmission costs are uniformly allocated using the 12-CP/75 - 25 SG factor. This is close to FERC's 12-CP/100 percent demand approach.

The remaining 35 percent of total cost of service is primarily distribution in nature. The costs of this component, excluding overheads and taxes, are essentially directly assigned to jurisdictions rather than allocated among them. The distribution component exhibits the greatest jurisdictional variation, ranging, on a per MWh basis, from a low in Idaho and Wyoming of $10 to $11 to a high in California of $41. In between are Washington at $14, Utah at $16, and Oregon at $22.

Summing the components for the period ending March 2002 shows Idaho with the lowest cost of service at $36 per MWh, Wyoming, $41, Washington, $44, Utah, $52, Oregon, $54, and California, the highest, $76. For the system as a whole, per MWh cost-of-service is $49. Notably, by September 2002, the end of the period covered by the next Semi Annual Report, weather normalized loads have declined slightly in Oregon and Washington and increased slightly in Utah. On a $/MWh basis, Idaho increases slightly to $37, as do Wyoming, $44, and Washington, $46; Utah increases to $56, while Oregon declines to $52, and California, though still the highest, declines to $74. For the system as a whole, the figure is $53. See Table 2.

Table 2. Semi Annual Report, October 2001 - September 2002.

	System	CA	OR	WA	WYP	UT	ID	WYU
Total Roll-In Results	$52.79	$74.33	$51.89	$46.00	$43.87	$56.21	$37.19	$46.14

These results are in part a product of the BPA credit. Using results of operations for the 12 months ending September 2002, the most recent available, costs that can be directly assigned to the production function, *excluding the BPA credit*, have now been examined. See Table 3. Directly assignable costs are not all production costs, but only those that are directly assignable because they are functionalized as production. They include production O & M expense, including fuel, production depreciation and amortization, gross production and mining plant, and accumulated depreciation and amortization of production and mining plant. Revenues from sales for resale have been attributed to the production costs as a revenue credit based on a wholesale sales factor used in the Company's last filed unbundled cost-of-service study in which 96.5

percent of such sales are allocated to production. On this basis, Wyoming-Pacific is lowest at $23.49, Oregon is second-lowest at $23.82, Wyoming-Utah is $24.50, Washington, $24.73, Idaho, $25.68, California, $25.99, and Utah, the highest, $27.84. Utah is 17 percent higher than Oregon and 13 percent higher than Washington. The system amount is $25.53.

Table 3. Direct-Assigned Production Costs, October 2001 - September 2002.

	System	CA	OR	WA	WYP	UT	ID	WYU
Excluding BPA Credit	$25.53	$25.99	$23.82	$24.73	$23.49	$27.84	$25.68	$24.50

An unbundled study of component proportions, focusing on changes in the apportionment of production costs, would show the consequence of these jurisdictional changes in load even more clearly. Such a study awaits the full-year results of operations to be reported in July 2003.

(2) When relative jurisdictional loads change, total costs are apportioned correspondingly.

To illustrate this point, consider the affect on jurisdictional revenue requirement if allocation factors based on 1998 loads were applied to current results of operations. Utah's jurisdictional revenue requirement would be about $80 million less than it is when allocation factors are based on current loads. The Utah division would be $97 million less. This test shows that growth in Utah relative to the other states does shift revenue requirement to Utah, even though the number of peaks and the proportion of energy in the allocation factors is unchanged. Further, as Utah expends more on demand-side management, directly assigned and valued at incremental cost, the State pays for more of its own load growth.

This shift in revenue requirement should be expected regardless of the then-current relationship between the cost of new production resources and the embedded cost of existing production resources. The reason is that total costs of providing service, not just production costs, are being apportioned to jurisdictions. For example, Utah's share of total revenue requirement, 38 percent, is higher than its system generation factor, 35 percent.

(3) Relative jurisdictional load growth alters each state's revenue requirement more than do deliberate changes in the number of peak months or the proportion of energy in the allocation factors.

In addition to the effect changes in jurisdictional load directly have on revenue requirement as load-based allocations factors adjust, there is also the effect that would occur if the number of coincident peaks or the proportion of energy in the allocation factors were altered. To show this, we first hold the current 75 - 25 demand-energy split constant but decrease the number of monthly peaks used in the capacity allocation factor to six from the current 12. A 6-CP (four winter months of November, December, January and February, and two summer months of July and August) allocation factor in place of the current 12-CP allocation factor would increase Utah jurisdictional revenue requirement $3.7 million, increase Oregon revenue requirement $12.6 million, increase Washington $6.0 million, and California $0.6 million. Only Idaho and Wyoming would benefit, with $16.8 million and $6.0 million decreases in revenue requirement respectively.

On the other hand, if the 12-CP allocation factor was retained but today's 75 - 25 production cost demand and energy split was altered to 50 - 50, Utah's revenue requirement would fall by $10.4 million. All other jurisdictions' revenue requirements would increase (Wyoming, $7.8 million, Oregon, $1.1 million, Idaho, $0.9 million, Washington, $0.6 million, and California, $0.15 million).

Our analysis reveals that for a given number of coincident-peak months, a jurisdiction's revenue requirement is linearly related to the proportion of energy included in the System Generation (SG) allocation factor. This linear relationship varies greatly among the jurisdictions. Its sensitivity depends on the relationship between system capacity (SC) and system energy (SE) allocation factors in each state. If the capacity allocation factor is greater than the energy factor, costs will decrease as more energy is included. Conversely, if the capacity allocation factor is smaller than the energy factor, costs will increase as more energy is included. The difference between capacity and energy allocation factors varies among the jurisdictions. See the attached file named Allocation Factor Sensitivity.xls.

Recent trends in jurisdictional load growth may or may not continue, but whatever does occur, load-based allocation factors steer costs in the right direction. Utah's growth is today more rapid than other jurisdiction's, but the pattern may reverse at some point, perhaps returning to the relatively more rapid Oregon growth that was the case at the time of the Utah - Pacific merger. The recent economic downturn, for example, appears to have been more severe in the northwest than in Utah, where the 2002 Winter Olympics, a continuing conversion to central air conditioning in the residential and commercial sectors, and the state's internal rate of population growth have supported rapid growth in electric demand. A method less responsive to change than is traditional cost allocation would be a source of interjurisdictional difficulty.

B. Demand-Energy Production Cost Split ("Classification").

Classification is the second of three main cost allocation method decisions (functionalization, which is not at issue, is the first) and one of the more important points for the Dynamic Alternative. The objective of the classification decision is the grouping of production cost by either of two measurable cost-defining characteristics of service, i.e.,whether costs are incurred to meet a demand or an energy purpose.[1]

It is not uncommon to classify fixed production costs as demand-related since, in general,

[1] The classification decision is an important aspect of either the Dynamic or the Hybrid Alternatives. In the former, its importance is due to reliance on traditional cost allocation for a single integrated system; in the latter, the decision is necessary in order to determine each state's share of control-area totals.

system capacity must be sufficient to meet maximum demand and thus costs are said not to vary with respect to kWh output. This is the "cost accounting" approach.

On the other hand, engineering analyses employing system reliability criteria in system planning might reveal that production costs are both demand- and energy-related, as would analyses showing that peak demand should be met with peaking plant while additional energy loads should be met with intermediate and baseload plant. This is said to justify the inclusion of some portion of energy in the allocation factor to be applied to production plant costs. Methods of this sort commonly employed by utilities, as catalogued by the 1992 NARUC *Electric Utility Cost Allocation Manual*, include the Peak and Average method and the Average and Excess Demand method, in which average demand (annual energy/8760) is related to energy and the remainder is related to capacity; the Equivalent Peaker method, which assumes peaking plant serves peak demand while intermediate and baseload plant serve additional energy load; and the Base-Intermediate-Peak method, in which baseload plant is assumed to have a large energy component while intermediate and peaking plant are assigned to given months and associated costs are allocated based on monthly coincident peak loads.

PacifiCorp (David Taylor, March 4, 2003) applied these NARUC *Manual* methods and produced a range of results. Demand-related production costs could vary from 100 percent, in the case of the cost accounting approach, to 37.5 percent (our approximation of the corresponding single result) for the Base-Intermediate-Peak method, to, at the low end, 27 percent using the Average and Excess Demand method. PacifiCorp also surveyed states, finding wide classification differences among them.

It follows that a range of demand-energy classification splits can be supported on a purely technical basis. Though cost-causation is the guiding principle, suggesting a need to understand the factors that influence utility plant investment decisions, the demand-energy split is also an equity or public policy choice insofar as results must be acceptable to the states, and within the states, to the classes of service. For example, at the time of the merger in 1989 it was necessary to meld two pre merger systems in a way that took into account their differing cost structures while minimizing the rate impacts occasioned by merging them. This led to the choice of the 12-CP capacity factor which was given 75 percent weight while energy was given 25 percent weight to form the system generation factor.

We face the same public policy problem today of mitigating potential rate impacts to some states. Whereas Part A above shows that changes in the number of coincident peak months produce relatively small impacts, changes in the amount of energy in the system generation factor can have very large effects on some states. Including more energy in the 12-CP factor, for example, benefits only Utah. It adversely affects Wyoming.

As a matter of public policy, any change should be premised not only on cost causation but also on fair apportionment of system costs to each jurisdiction. All things considered, the range of reasonable choices includes the current 75 percent demand, 25 percent energy split.

From the standpoint of its impacts on jurisdictions, the classification choice is not independent of the selection of months for the capacity allocation factor or decisions on other Dynamic Alternative elements.

C. Allocation of Demand-Related Production Costs.

Demand-related production costs are allocated to jurisdictions using a capacity allocation factor. For the 75 percent of PacifiCorp's production costs that are demand-related, this has been a 12-coincident peak factor, one in which, in other words, all months of the year have a role. This was the decision reached in 1992. It is now being revisited as part of the Dynamic Alternative in order to address the MSP concern that the principle of cost causation today might dictate selection of a different set of months.

Stress factor analysis is the principal means by which particular months can be identified for the capacity allocation factor. Stress factors include existing and forecast monthly firm retail and wholesale peak demand; probability of contribution to peak; monthly reserve margin, adjusted for maintenance and expressed as the capacity cost to maintain a 15 percent reserve margin; and loss of load probability. As PacifiCorp does not produce the loss of load probability statistic, a GRID modeling category called emergency purchases is used as a substitute. PacifiCorp developed the historical data for each factor for fiscal years 2001 and 2002, and used forecasts consistent with *IRP 2003* for fiscal years 2004 through 2008. Though information for a 20 percent reserve margin and for emergency purchases as a surrogate for loss of load probability was developed, these measures were not used for the analysis which follows. Both seemed problematic, and removing them did not alter the results.

While each factor can be examined separately, two methods, termed rationalizing and normalizing, were employed to develop composite results. Rationalizing means developing a ratio that compares the peak demand of a given month to the month of the maximum peak demand for the year. Normalizing means constructing a measure, also a ratio, the numerator of which is the peak demand of a given month less the minimum of peak demands occurring in the year, and the denominator of which is the difference between the maximum and minimum of peak demands occurring in the year. A preference has been expressed for the use of the rationalizing technique because the normalizing technique gives the minimum month a zero value when in fact that month may differ little from those that stress the system.

Using the rationalizing and normalizing techniques, composites of three stress factors have been developed. The three factors are firm peak demand, probability of contribution to peak, and the cost to bring reserve margin to 15 percent. Composite measures for each month are obtained by averaging each measure across all years and then weighting each of the three equally. Implications of these results are shown in the appended charts. Composite measures for each month are presented for three cases: firm peak demand as the sum of retail plus wholesale demand, as that sum minus the Cholla/APS contract, and as retail demand only.[2]

With firm peak demand as retail demand only, or with removal of the Cholla/APS contract, stress factor analysis may suggest a smaller set of months for the allocation factor than the current 12. Wholesale sales and this contract both exert a disproportionate influence on summer months. When firm peak demand is the sum of retail plus wholesale demand, stress factor analysis may not make a compelling case for movement from the capacity factor's current 12-coincident-peak basis. The system appears to face stresses in all months, with the possible exceptions of April and May. When peak demand is retail demand only, stress factor analysis might suggest removal of other months as well.

The question is whether stress factor analysis gives sufficient reason to change the capacity allocation factor to something less than 12 months. Several points call for caution in interpreting results. For example, the disproportionate impact on summer months of exchange contracts and wholesale sales is a remnant of earlier PacifiCorp decisions. It is worth asking whether this will continue. The analysis conducted by PacifiCorp of the retail-demand-only case is based entirely on forecast loads, unlike the retail plus wholesale case in which two years of actual loads are analyzed. There are apparent differences between historical and forecast loads. While little variation around the average appears in forecast loads, large year-to-year variations exist in historical loads. Moreover, the rationalized stress factor composite shows nine months at greater than 90 percent of the peak month; six months are greater than 95 percent.

With the Cholla/APS contract removed, the stress imposed by winter months increases, and on this basis fewer months might be indicated for the allocation factor. The rationalized stress factor composite for this case shows some months as low as 45 percent of maximum, and in the months that are candidates for deletion, hydro runoff is high and market prices are low. On the other hand, PacifiCorp meets peak requirements increasingly through market purchases, suggesting less reason to single out the highest monthly peaks only for the allocation factor to be applied to own generation capacity. Finally, control area (in contrast to system) stress factor information raises further doubt about removing months which might register slightly less stress than others when examined at the system level.

Whatever the answer given by stress factor analysis, the capacity allocation factor chosen will have to be reasonable from the public policy standpoint, and this involves not only the principle of cost causation but jurisdictional impact. The attached charts show the jurisdictional impacts of changes in the number of months in the capacity factor and in the percentage of production cost classified as demand-related. (Stress Factor Analysis.xls.)

D. Allocation of Energy-Related Costs.

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[2] These are separate studies, two of which are in response to data requests. They have been combined, and are available to those who have signed protective agreements. See the attached file named Stress Factor Analysis.xls.

Given that Oregon's proposed reformulation of the energy allocation factor (SE) on an hourly basis would shift costs among jurisdictions *less than one percent*, and the modeling basis for any such change raises problems, Utah parties support retention of the annual basis for the allocation factor.

Principal among these problems is the unknown ability of GRID, the modeling tool the Company would employ to formulate an hourly factor, to produce acceptable hourly results. Only recently has this model been through a benchmarking test of its estimation of normalized annual net power cost. The annual net power cost test was not designed to examine the reliability of the model's hourly estimates. No hour-by-hour test of the GRID model has been conducted.

PacifiCorp reports that differences between annual and hourly results are driven by model inputs such as market prices, relative jurisdictional loads, and system balancing quantities. These differences are most sensitive to hourly market prices and loads. Misallocation of energy-related purchase costs and sales revenues on a GRID-modeled hourly basis therefore may occur.

This is the status of analysis to date. Modeled hourly results may not be reliable, and the prospect of auditing 8760 hours to ensure a proper basis for the allocator is daunting. Changing the basis for the energy allocation factor along lines proposed has little effect on jurisdictional cost allocation results, but if an hourly allocator were to be employed a wholesale jurisdiction, as discussed below, would become a necessity for interjurisdictional cost allocation.

2. Wholesale Jurisdiction.

Utah Parties advocate formation of a wholesale jurisdiction in the event the MSP adopts proposals that rely on hourly interjurisdictional cost allocation techniques.[3] We make no recommendation at this time about the transactions belonging in a wholesale jurisdiction, but observe that any wholesale load appearing in the integrated resource plan is a likely candidate.

In 1997, wholesale sales were some 50 percent of PacifiCorp total firm sales. The Company's *Integrated Resource Plan 2003* indicates the fiscal 2002 share is still about 34 percent, larger than all but the Utah jurisdiction. A wholesale jurisdiction would be one way to monitor the costs and risks of wholesale activity, and this could be done while still maintaining the current revenue credit mechanism.

There is a second, more immediate reason for a wholesale jurisdiction. Because the revenue credit is allocated as the net annual benefit of wholesale activity, the current interjurisdictional cost allocation method shares the effects of wholesale activity uniformly among the states. But the MSP investigation of interjurisdictional cost allocation methods may

[3] The need to address these issues is even clearer in the case of the Hybrid Alternative because it splits the integrated system into control areas and employs interchange accounting on an hourly basis.

yield changes that do not have this equitable outcome. For example, since wholesale sales and exchanges vary in cost and magnitude throughout the year, the MSP proposal to change from an annual to an hourly energy allocator could, by allocating some of the revenue credit on an hourly basis, apportion the credit inequitably. Moving from an annual to a time-differentiated basis for energy allocation makes the timing of wholesale sales and purchases and the timing difference between exchange contract receipts and obligations a particular concern. These timing effects could lead to a disproportionate and inequitable distribution of costs and benefits across state jurisdictions, an effect that has been recognized in studies provided by PacifiCorp for the MSP. Other proposals which rely on hourly allocation methods might, however inadvertently, raise similar problems. Responding to the effects of cost allocation changes therefore is an important reason for the jurisdiction.

3. Transmission Cost Refunctionalization.

Since it is applied uniformly across jurisdictions, Utah Parties support the current functionalization of transmission costs for interjurisdictional cost allocation purposes. This position will not change unless and until sufficient external reason, such as a regional transmission organization requirement, arises.

Though FERC has proposed a seven-factor test to guide any necessary refunctionalization, the need for it now may arise only when regional transmission organizations are implemented. Unbundling retail service with separate identification of transmission service could be the cause. If so, the context would be the RTO process’s recognized need to avoid cost shifts. RTO implementation may be years away, and its details are as yet unclear. Oregon, however, initially proposed transmission refunctionalization as an MSP task.

For interjurisdictional cost allocation, the costs of facilities 46 kV and above are currently functionalized as transmission. Because this cost allocation treatment is uniform across jurisdictions, Utah Parties believe the subject need not be addressed by the MSP. Further consideration should be reserved for RTO development, where, if it arises, it can be addressed during the state-level approval process.

PacifiCorp has not, and we are informed will not, recommend any change in transmission functionalization in connection with RTO West. The Company is working with other participants to gain support for this view. FERC has not imposed a functionalization model for RTO’s, so it will not be known until after RTO West participants file at FERC (no sooner than July 2003) and FERC rules (perhaps Winter 2003) whether the current functionalization will continue.

4. Hydro Endowment.

MSP Study 50 suggests that, on balance, both east and west are better off merged than independent. This Study therefore provides no clear evidence supporting a hydro endowment.

The Study illustrates the rate stability and risk sharing benefits of merged system operation. Study 50, however, cannot be considered definitive in that it depends on controversial assumptions. For this reason, Utah Parties do not close the door to consideration of an endowment. Were Utah Parties to find a hydro endowment acceptable, it could take the form of a fuel cost adjustment, as is now the case in Modified Accord. But this adjustment would be based on PacifiCorp's own hydro resources and pre merger steam plant only. As pre merger plant costs are to be allocated rather than directly assigned to divisions, hydro relicensing costs likewise should be allocated. It follows that as specific hydro plant is relicensed, and thermal plant retired, associated operating costs and output would be removed from calculation of any hydro fuel cost adjustment.

As an element of the Dynamic Alternative, we have considered the Oregon - Washington desire to continue, though enlarged under the terms first proposed, a hydro endowment in interjurisdictional cost allocation. Our analysis centers on MSP Study 50, with the view that an inconclusive Study 50, or the persuasive effect of other criteria, may convince Utah Parties to support such an endowment.

Study 50 is intended to divide the PacifiCorp system into two parts, and to model each as a separate optimizing entity. The separation is on pre merger grounds rather than the Hybrid Alternative's proposed control-area split. Though both approaches require careful consideration of and agreement on the resources and loads to be part of each area, the pre merger split is preferred for Study 50 because it better contrasts how hypothetical, current operations of the Companies, if they had not merged, would compare to today's merged-system operation. Study 50 should therefore reflect the resources each Company brought to the merger, as well as the resources (generation, transmission, wholesale transactions plus exchanges) each, as optimizing companies, might now have if no merger had occurred.

We are relying on the same models for Study 50 that PacifiCorp employs for the other MSP studies, so Study 50 faces the same modeling advantages and limitations that they do. Among the factors which condition any interpretation of Study 50 results are the absence of nonfirm transmission operations, the apparent need to model how FERC Order 888 might have affected the transmission rights and resources of each Company had there been no merger, and possible inequitable distribution of the costs and benefits of wholesale transactions and exchanges resulting from assignment of them to one area or the other. Another limitation is the absence of the separate integrated resource plans each unmerged Company would be expected to have. In their place, model runs rely on *Integrated Resource Plan 2003* from which resources for each side are selected (a ".4 study"). Even with these limitations, we have no more objective basis than Study 50 to reach conclusions about the interjurisdictional fairness of a hydro endowment.

A complete Study 50 was received by Utah Parties on May 15, 2003. Our review of it reinforces the concerns about limitations just stated. Though we would question the Study's placement of Wyoming load and resources, transmission opportunities and limitations as these affect inter "company" sales and purchases, and the assignment of certain contracts and exchanges, we believe the Company has made a reasonable attempt to model separate optimizing entities. As with the above limitations, these modeling assumptions condition the conclusions that can be drawn from Study 50.

Study 50 results provide no clear evidence for a hydro endowment. There are reported years in which merged operations are better, and years in which either west or east might be better off independent.

The unambiguous conclusion to be drawn from Study 50 is the lack of any significant difference, regardless of year, among total company results whether under Modified Accord, Roll-in, or summed for two independent companies. The difference between Study 50 divisional "island" results and an integrated system ranges between a 0.7 percent to a 1.8 percent increase in revenue requirement, and averages about 1 percent across the study years 2004 - 2018.

An integrated single system has two distinct benefits shown by the Study. First, since cost differences are small across the years, rates based on total company cost-of-service would be stable. This is not the case for the two independent companies because their jurisdictional revenue requirements are affected to a much greater extent by acquisition of new resources than is the integrated system. Second, risks in the case of separation are greater than when shared across a single integrated system. These two values, risk sharing and rate stability, are from the beginning part of the argument for the Dynamic Alternative. See attached MSP Study 50.4.xls.

5. Direct Access

During the time this institutional change remains uncertain and potential moves to market small, Utah Parties believe that absorbing the loss of direct-access load, as we discuss it below, may be the best approach. But if a wall-off of direct-access effects is required, Section B shows how the Dynamic Alternative would accomplish it.

The possibility of direct access has raised the question how to enable the direct-access jurisdiction to move forward with its initiative while at the same time preventing cost recovery problems and protecting customers in other jurisdictions from potential cost shifts. The answer will depend on the administrative rules governing direct access. A second key will be the effects direct access will have on resource planning. At the present time, possible direct access is confined to a single jurisdiction, Oregon, where rules are unresolved. Whether new resources should be valued only at market is a concern in that State. We note that the recent effort to define requirements for competitive bidding for new resources may address the point. Direct access could occur more broadly, of course, as part of a general restructuring of the industry. But as described in Part B below, the Dynamic Alternative we specify should accommodate it.

We ignore the case in which PacifiCorp acquires direct access load. If any such gain is immaterial, there is no need for a special response; if the gain is large, any acquired direct access load which retains the ability to shop for power either should not be a regulated utility obligation or should be treated like any other market sale.

A. Absorb the Loss of Load

The loss-of-load approach assumes the utility is not directed to retain resources to serve load lost to direct access. This load, in other words, will not appear in the integrated resource plan. No regulatory response to direct access need occur; that is, a new interjurisdictional allocation policy or practice is not required. Even with respect to magnitudes, this is no different than the removal of Sandpoint, Idaho, the entire Montana jurisdiction, and Cody, Wyoming, or the proposed sale of the California jurisdiction.

When one jurisdiction though not others allows customers to shop for power supply, a load converting to direct access is simply lost load, no different than typical lost load, and its consequences will be absorbed by all jurisdictions. Though the load loss causes an allocation factor adjustment, as is normal when load characteristics change, no special interjurisdictional allocation steps need be taken. Fixed resources formerly serving the lost load will now serve remaining load and, as economical, the wholesale market. Costs, both net power costs and resource acquisition cost in the long term, will be lower as a consequence.

In PacifiCorp's newly released *Integrated Resource Plan 2003*, the results of a case testing the loss of a 400 MW direct access Oregon load reveal a $1.78 billion reduction in the 20-year present value of system revenue requirement. The loss of load may delay the time when new resources will have to be acquired, and perhaps alter the size and kind to add. This translates into about a $1.30/MWh reduction in incremental system costs due to the loss of load. (*Plan*, pp. 135-136.)

The balance of cost and benefit to remaining customers depends on factors including the rate and character of system growth, the relative growth rates of the jurisdictions, and the future prices of owned and market resources. Moreover, there are benefits worth preserving that could be foregone if a more comprehensive, anticipatory regulatory response to hypothetical direct access, such as the Hybrid Alternative, were taken. These include the ability to exercise a less intrusive approach to actual problems as and when they arise, a continuation of systemwide risk-sharing, and a continuation of traditional cost allocation methods that are consistent with system planning and operation.

Taken as a whole, benefits may offset costs without the requirement of further action to protect customers in other jurisdictions. Anticipatory regulatory action before the actual terms and extent of direct access are known is not required. In other words, in its current status direct access is a case-specific issue rather than one which requires comprehensive before-the-fact regulatory action.

B. The "Wall-Off"

If the actual terms and conditions under which direct access is permitted are such that the loss of load creates an interjurisdictional cost allocation problem, as may be the case in so far as the utility is required to retain or plan for the resources necessary to serve a departed direct access load, a "wall-off" of cost allocation effects may be necessary. This case differs from the loss-of-load approach just described in that the Company is assumed to be required to include the loads lost to direct access in its Integrated Resource Plan (IRP). Thus, the IRP will describe a preferred portfolio of Company resources and purchases which is optimal, from cost, timing, and risk perspectives, in serving all loads, including the direct access loads.

The wall off can be accomplished in two steps. First, the loads lost to direct access will be included in jurisdictional load-based allocation factors so that the embedded cost of serving all load will be allocated to all jurisdictions. This means that the direct-access jurisdiction will receive a full allocation of the embedded cost associated with the lost load but only an allocated share of any cost decreases and revenue increases made possible by that loss of load. In order to treat the direct-access jurisdiction fairly and to prevent the other jurisdictions from benefitting inappropriately, a second step will be necessary. In this second step, net power cost studies will be used to obtain a measure of the incremental value (i.e., incremental cost decreases and revenue increases or revenue credits) associated with lost load. This value will be directly assigned to the direct-access jurisdiction. A more complete description follows.

As a consequence of lost load, net power costs will fall, either as a result of decreases in fuel and wholesale purchase expenses incurred to serve a reduced total load, or increases in revenues from increased wholesale sales made from resources no longer used to serve customers who have opted for direct access. For ratemaking purposes, actual net power costs are replaced by normalized net power costs obtained from the Company's GRID model, an hourly optimization model. In the GRID model, loads lost to direct access will be included as loads served by the Company, thereby providing the normalized value of net power cost had the Company actually served these loads. The components of this normalized value of net power cost will then be allocated to all jurisdictions. As a consequence, the jurisdictions not adopting direct access will be indifferent to the loss of load in the direct-access jurisdiction; that is to say, they will be walled-off from the effects of that jurisdiction's policy decision.

The normalized net power costs recoverable from the direct-access jurisdiction will have two pieces in the wall-off approach. First, as just stated, that jurisdiction will have its allocated share of net power cost derived by including direct-access loads in the calculation. Second, the difference in normalized total net power costs *with and without direct access loads* will be calculated and that amount will be available to the direct-access jurisdiction. Thus all reductions in net power costs associated with lost loads, whether the result of decreases in fuel or wholesale purchase expenses or increases in wholesale sale revenues, accrue to the jurisdiction that adopts direct access. The effects of this final step are fair treatment for the direct-access jurisdiction and recovery by the Company of the normalized net power costs associated with the loads it actually serves.

If more than one jurisdiction were to adopt direct access policies under the condition that the Company retains an obligation to serve departing customers if they choose to return, then the same process could be followed. The reduction in total net power cost due to lost loads, however, would be allocated among the direct access jurisdictions based on relative lost loads.

6. Washington Carve-Out.

In MSP discussions, Washington staff reveals a desire for a Washington-specific integrated resource plan. Staff also suggests that a specific set of PacifiCorp's production resources should be the basis for Washington's rates. The reason for this seems to be a perception that integrated single-system planning and operation is detrimental to that State's interests.

The Dynamic Alternative, by contrast, is premised on integrated single-system planning and operation, and a cost allocation method consistent with it. We support single-system planning, as in PacifiCorp's *Integrated Resource Plan 2003*. By operation, we mean not only the physical flow of power from resources to loads but also the economic management of generation and transmission assets and contracts to minimize net operating cost for all customers. For example, sale of power in off-peak hours generates revenues to offset purchases in the same or other hours, irrespective of transmission limits, and this activity helps baseload plants to run at minimum efficient cost. Although a unit (or purchase) may be brought on line to meet nearby retail growth or to replace an expired purchase contract, the economic use of the new unit will be driven by actual daily conditions and opportunities to minimize cost. All customers benefit from lower per unit costs of operations.

Our examination of the traditional interjurisdictional cost allocation method, and the scope for constructive change, does not reveal general unfairness to Washington. Our analysis of production costs for each state shows Washington's per unit costs to be lower than Utah's. In addition, Study 50 shows that in the near term Washington costs are slightly lower as part of the integrated system than as part of a separate division. Participation in an integrated system also provides Washington the benefit of greater rate stability. Finally, as Utah increases its emphasis on demand-side management, valued at incremental cost and directly assigned, Utah's per unit total cost may rise even further relative to Washington, and Utah will directly pay for some of its load growth.

Should Washington parties remain unconvinced, the State might resort to the rate case process, in which the means of evaluating either operational or resource acquisition decisions are well established. The Washington Commission can consider and decide whether system facilities are used and useful and have been acquired prudently. In other words, in the Dynamic Alternative, pursuit of a solution within a jurisdiction can occur, giving PacifiCorp the opportunity to demonstrate prudent resource acquisition decisions, effective and efficient operations, and just and reasonable rates.

7. Special Retail Contracts.

All firm special retail contracts are situs and therefore raise no interjurisdictional cost allocation difficulty. The special retail contract for interruptible service, however, is distinguished from others in that it yields system benefits. Utah Parties develop an interjurisdictional cost allocation approach for such contracts that properly apportions the costs, benefits and risks of interruptible service.

Our cost allocation proposal follows from the principles that cost allocation should be consistent with system planning assumptions, should encourage economic efficiency, and should assure equity both among states and between shareholders and customers. Further, it should be consistent with the type of system benefits received by customers.

Allocation of the costs of non-standard service as we propose to do it will be based on the cost reduction or other benefit made possible for firm retail customers. Cost reductions arise from either or both capacity cost avoidance and net power cost savings. It is the inclusion or exclusion of the interruptible load in system capacity planning that determines the kind of cost saving interruption yields. When load is *excluded* from the integrated resource plan, capacity costs are reduced by the amount of load reduction. When load is *included* in the integrated resource plan, cost savings from interruptible service flow from reduction of net power costs. System benefit may also be in the form of reduced service disruption.

We identify three kinds of non-standard or interruptible retail service that could provide system benefit. These are termed operating reserve, system integrity, and economic curtailment. Should there be others, the decision rules we develop here would apply to them as well.

Operating Reserve. Operating reserve requirements are part of system integrated resource planning. Operating reserve is necessary to provide reliable service to customers. Voluntary rules prescribe the amount of capacity utilities must hold in reserve in order to recover from unplanned generation outage or western grid transmission failure. The operating reserve requirement reduces the likelihood of retail service interruption. PacifiCorp firm retail customers benefit equally by experiencing continuous rather than unpredictable service.

In order to provide operating reserve, PacifiCorp can build generating capacity, purchase reserve from another generator, or for up to 50 percent of the requirement, call upon a customer to reduce its demand for power. All system customers benefit when PacifiCorp minimizes the cost of providing operating reserve.

The Company's integrated resource plan analyzes lowest cost options for operating reserve. When service interruption is used for operating reserve, it is reflected in the plan. The interruptible load is excluded from integrated resource plan peak load requirements prior to determining future capacity additions. Retail customers will be indifferent to whether the direct cost of operating reserve is obtained from service interruption or from lowest-cost, owned or purchased supply capacity. They additionally benefit from lower indirect costs if service interruption, in place of additional supply, lowers emissions and reduces the risks of future environmental compliance costs and fuel price volatility.

Our proposal is designed to ensure equity between customers and shareholders and among states, and to encourage economic decisions by utility management. It does so by allocating to firm customers the cost of the operating reserve associated with service interruption, and by directly assigning revenues to the host jurisdiction. The proposal has the advantage of allowing the host jurisdiction to review and approve the rates, terms and conditions of service for this customer, and has that jurisdiction bear the risk that the approved contract is compensatory. The other states are insulated from this decision. Remaining firm service customers bear the capacity cost of serving load subject to interruption for operating reserve and this cost is essentially valued at average system capacity cost by reformulated allocation factors which exclude the load from the host jurisdiction. Shareholders benefit because utility management negotiates the prices, terms and conditions of service which are subject to review in only one state.

We propose the following allocation procedure. First, the demand excluded from the integrated resource plan as a result of this form of interruption is removed from observed, weather-adjusted demand in a given test period to form the system capacity (SC) cost allocation factors. Thus, existing production plant costs will be allocated on all units of demand except for the demand subject to operating reserve interruption. The host jurisdiction will be allocated capacity cost only on its firm retail demand and thus is relieved of capacity cost associated with the load subject to operating reserve interruption.

Second, the energy (megawatt hours) consumed by the interruptible customer will be included in the formation of system energy (SE) cost allocation factors because the customer's energy requirement is served by and imposes energy costs on the system. Similarly, the energy requirement will be included in net power cost. Thus the host jurisdiction will be allocated a share of system energy costs to serve the interruptible customer's energy requirements. Since this form of interruptible service does not avoid the fixed and variable costs of transmission, overheads, and other non-production cost currently allocated using the System Generation (SG) factor, it will be necessary to form additional System Capacity (SC) and System Generation factors based on the inclusion of the interruptible customer's firm plus interruptible load.

In the third step, revenues from this customer will be directly assigned (situs) to the host jurisdiction in order to recover the energy and overhead costs allocated to it. Whether these revenues result from a cost-of-service rate discounted for service interruption or are determined as a "non-firm" rate is unimportant to remaining jurisdictions. As long as the host jurisdiction recovers adequate revenues from the interruptible customer for energy costs and fixed overheads, the host jurisdiction will be made whole.

A numerical example of this cost allocation method is shown in Table 1 entitled

"Operating Reserve" in the attached spreadsheet, Special Contract Tables.xls.

System Integrity. System integrity interruption enables the Company to provide reliable service to customers. This form of customer interruption is invoked in the event of a physical system emergency. We interpret this to mean it will be invoked at a North American Electric Reliability Council Stage 3 System Emergency Alert. At a Stage 3 alert, all non-firm demand is already cut. (Non-firm wholesales sales are cut at Stage 1 and non-firm retail demand is cut at Stage 2) Thus, system integrity interruption is about queuing firm demand for load shedding in order to mitigate widespread service disruption.

To the degree a customer is willing to go first, other customers benefit by experiencing continuous service. It follows that local customers benefit when the system emergency is local, and direct assignment of cost will be appropriate. If the emergency is systemwide, allocation of cost will be appropriate.

We propose the following allocation procedure. The demand associated with system integrity interruption is firm retail demand for planning purposes (it is included in the integrated resource plan) and will therefore be included in cost allocation factors and net power cost studies. To the degree benefits are local, the cost of the option to cut this customer first in a Stage 3 alert should be situs. To the degree that benefits accrue outside the local area, the cost of the option to cut this customer first should be allocated using the SG or SE factor.

A numerical example showing the approach under the assumption of systemwide benefit is shown in Table 2: "System Integrity" in the attached spreadsheet.

Economic Curtailment. The following description assumes that the load subject to economic interruption is included in the integrated resource plan; i.e., the Company plans to build or buy capacity to serve the load. Economic curtailment provides a hedge against high power costs when a special contract customer agrees to service interruption in exchange for a discount on the power it buys from the utility. In some cases, the customer may wish to buy-through the proposed interruption and incur the cost of doing so. The benefit to remaining customers is the avoidance of high-cost power purchases. Shareholders benefit from reduced cost recovery risk between rate cases.

In the case when buy-through is not allowed, we propose the following allocation procedure. To reflect costs avoided, the net power cost study used to normalize power costs for setting rates must model the terms and conditions of the economic interruption. The study will then reflect, on a normalized basis, the value to the system of economic interruption. Net power costs are then allocated based on the normalized loads emerging from the net power cost study. The option cost of obtaining the interruption is included in the net power cost study and allocated based on normalized loads.

Since the benefit of economic interruption is a hedge against high prices, and "normal" market prices prevail in setting rates, little value to firm customers may appear in normalized results. Greater value may emerge over time as “normal” market prices rise relative to economic curtailment terms and conditions, and form the basis for setting new rates. However, the benefit to shareholders between rate cases remains, and to the extent earnings are more stable, customers benefit from rate stability and a financially healthy company.

A numerical example showing this approach is shown in Table 3: Economic Curtailment - No Buy-through Allowed, in the attached spreadsheet.

In the case when buy-through is allowed, we propose two methods. The first is a modification to the above procedure when buy-through is not allowed. After a net power cost study is performed based on the terms and conditions of economic interruption and allocated based on normalized loads, cost and revenue adjustments are made to the host jurisdiction. The option cost of the buy-through is directly assigned to the host jurisdiction and contract revenues are directly assigned to it. PacifiCorp’s results of operation will sum to 100 percent. Since the cost does not appear in the net power cost study that is the basis of allocated net power cost, and the revenue from the buy-through is directly assigned to the host jurisdiction, no other changes are necessary to remaining jurisdictions.

This approach is shown in Table 4: Economic Curtailment; BT Method 1, in the attached spreadsheet. It can be seen from the “Summary and Description” tab that economic curtailment with buy-through, method 1, yields the same result as economic curtailment without allowance of buy-through. This is purely a matter of concern for the host jurisdiction. However, remaining jurisdictions or PacifiCorp bear the risk that the contract terms adequately capture the cost of the buy-through over time.

The second method would allocate normalized net power costs *including* the economic curtailment load option. The cost to obtain the interruption would be allocated based on observed (weather adjusted) loads. Revenues from the buy-through sales would be directly assigned to the host jurisdiction.

This approach is shown in Table 5: Economic Curtailment; BT Method 2. It can be seen from the “Summary and Description” tab that economic curtailment with buy-through, method 2, yields results that allocate greater cost to the host jurisdiction than method 1. This is because greater responsibility for contract compensation is placed on the host jurisdiction when loads are included in forming the cost allocation factors.

8. Sale or Purchase of Service Territory.

MSP discussions do not suggest a controversy where the effects of the sale or purchase of service territory are small. If the effects are potentially large and significant jurisdictional impacts may occur, resolution should be, as it is now, case-specific.