PNW Resource Adequacy Forum
Small Group Description of Resource Adequacy Implementation Alternatives

INTRODUCTON

Steering Committee Principles

The Steering Committee set out four principles early in its deliberation. The last three of the four dealt with application of a regional Resource Adequacy (RA) metric and target to individual utilities:

- We should develop mechanisms to assess whether regional RA metric and target are met.
    - One mechanism is a reporting process to get data from individual load serving entities for regional assessment.
    - This allows region-wide transparency and allows individual utilities to assess themselves with respect to their position in the Region.
- There should be some mechanism reasonably to assure that the regional metric and target will be met going forward.
- Don't trample on the jurisdiction of states or prerogatives of individual utilities in planning and acquiring resources to meet load.

This paper presents three alternative approaches for implementation of the Northwest RA target and metric at the individual utility level. The four approaches are the following:

- Alternative 1: Rely on public information and market discipline
- Alternative 2: Rely on some entity or entities to be responsible for providing the adequacy reserve, either the utilities through binding contractual or regulatory requirements (Alternative 2a), some other entity (Alternative 2b), or through a voluntary contractual mechanism similar to the Western Electricity Coordinating Council's (WECC) Reliability Management System approach (Alternative 2c)
- Alternative 3: Rely on the control areas to be responsible for providing the adequacy reserve.

Application of the Regional Resource Adequacy Metric

The Pacific Northwest region is proposing an energy resource adequacy standard[1]. This standard would be tracked by monitoring the region's annual load/resource balance, defined as the available average annual energy minus the average annual firm load, where

- The resource available is the average annual energy defined as the sum of
    - the energy capability from all non-hydro resources …; plus
    - the hydroelectric system energy based on critical water conditions; plus

[1] Full description and details are provided in ….

- 1,500 aMW of "planning adjustment" energy [a proxy measure for hydroelectric system flexibility, availability of out-of-region surplus capacity, and other factors] …;
- The average annual firm load is based on average temperature conditions and is adjusted for firm out-of-region energy contract sales and purchases.[2]

A capacity metric and target will also be proposed, but the details have not yet been worked out. The implementation approaches described in this paper are not expected to be affected by their later inclusion.

Practical issues surround the application of this regional metric to the set of smaller entities that comprise the region as a whole. The regional resource adequacy construct implies that within-region uncommitted market resources and out-of-region surpluses can be allocated to those entities responsible for providing generation and load service in the Pacific Northwest. The application of this resource adequacy measure to individual entities must address this allocation feature.

In general, load-serving entities focus on the cost and availability of resources and wholesale power contracts necessary to meet commercial sales obligations. Load-serving entities rely in part on firm market transactions to meet their firm load. Intra-regional market resources and out-of-region surpluses are allocated through this process, including the disposition of power generated by the region's Independent Power Producers (IPPs). While these transactions may be consummated months in advance of actual delivery, the actual generation associated with these transactions is oftentimes not identified until "next-day" pre-schedule deadlines. Much like the birthday game of "musical chairs," if a load-serving entity is relying on firm or market purchases to meet load but a generation source for that transaction is not available "when the music stops playing," reliability will be compromised. Thus, any measure of resource adequacy applied to a subset of the region must address the allocation of within-region market resources and out-of-region surpluses among these entities.

Wholesale market contracting practices further compound the allocation problem. Many transactions occur in the Northwest under the terms of the Western Systems Power Pool Agreement (WSPP Agreement). Under the WSPP Agreement power is commonly traded as

- interruptible at any time for any reason (Schedule A);
- contingent on the operation of a specific generation unit (Schedule B);[3] and
- a firm commitment to deliver power, regardless of the operation of specific generators where, unless specified otherwise, interruption of firm transmission excuses deliveries under *force majeure* (Schedule C).[4]

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[2] An assumption that up to 3,000 MW of surplus capacity is available to the region during any "winter" hour during December through March underlies this metric.

[3] Confusion and controversy surrounds whether or not Schedule B products must carry sufficient reserves such that deliveries are maintained during the "scheduling hour" in the event that the generation unit experiences a forced outage.

Most transactions occur as "Schedule C" firm power, which from a planning point-of-view constitutes a more reliable source of supply from among the three products, as the seller has a "system" obligation to provide the power from any number of (non-specified) sources. Once a Schedule C product is actually scheduled, however, it is matched with a "source" control area through its corresponding NERC "tag." The source control area contains the generation unit underlying the transaction. Unlike the unit-contingent "Schedule B" product, Schedule C power deliveries must continue over the term of the contract, even if the generation unit associated with the scheduled transaction goes off-line.

The commercial terms associated with the above products remain in a state of flux. Controversy and inconsistent practices surround the provision of operating reserves associated with the Schedule B and Schedule C products. Under the scheduling practices in place in the Pacific Northwest, the seller of Schedule C power is required to carry operating reserves, which implies power deliveries will be maintained even in circumstances where the underlying power delivery schedule may be cut during the scheduling hour.[5] However, some areas of the country require that the "load serving entity carry operating reserves," implying that any Schedule C power deliveries that are curtailed in actual operations would be made whole by the buyer's operating reserves.[6] This would preclude a reliance on Schedule C transactions to fulfill Resource Adequacy requirements, as the purchasing utility would be required to maintain operating reserves sufficient to replace the contracted for amount in the event of curtailment. An appendix provides further background information on Northwest utility contracting.

Key Assumptions for all Alternatives

Some of the prerequisites and assumptions underlying the successful implementation of all of the alternatives include:

- The PNW RA Forum (Forum) has reached agreement on both energy and capacity metrics and targets that are deemed to satisfy an acceptable Loss of Load Probability target on a Regional basis;
- The Forum has successfully translated the Regional metrics and targets into individual RA metrics and targets, which equitably allocate the "planning adjustment" energy and capacity (if any) as well as the uncommitted within-Region market resources to the individual utilities;
- The Forum has defined an appropriate planning year, perhaps three years out into the future, for which a resource adequacy assessment performed by the NWPCC, which indicates insufficient resources deliverable to load to meet the agreed-upon

[4] Considerable controversy and confusion surrounds the "liquidated damages" provisions of the Schedule C product. A common interpretation of this provision is that the requirement to provide liquidated damages does not excuse firm delivery, it simply defines the penalty for a failure to deliver.
[5] This practice is under review by the WECC Operating Reserves Standard Task Force.
[6] This could be applicable due to either the interruption of a transmission path or the interruption of underlying generation.

regional metrics and targets, triggers actions on the part of BPA and the PUCs to ensure procurement of additional resources, for the alternative(s) requiring their action;
- Although the most important goal of all alternatives is to ensure resource adequacy for the Region, another important goal is to avoid mechanisms that result in overbuilding generation in the Region.

ALTERNATIVES

Alternative 1: Information And Market Discipline

Utilities, other than those that have chosen in advance to put their entire load on Bonneville, report their load and resource forecasts annually to some regional entity. Bonneville would report for all the utilities that have chosen it as their ongoing resource supplier. Currently the utilities with resource responsibility do this through PNUCC, and PNUCC would be a good candidate for this role in the future.

The results of this reporting would be used in an assessment, in which the regional totals would be checked against the regional energy and capacity metrics and targets. Independent analysis of loads, e.g., the Council's, and of resource availability could be brought to bear in this assessment as well. Utilities would be able to see how they looked in the context of all the regional utilities and adjust their plans accordingly.

Utilities that were short in a crunch, for whatever reason, would face the market price consequences of their actions. Public customers of Bonneville that had chosen not to rely on Bonneville would face overrun penalties in the tariff for going beyond their allocated amounts. The tariff penalty should be set at something above the market price for the replacement power that Bonneville would have to acquire on the spot market to serve the overrun amounts. Bonneville's current imbalance penalty, which is administered through the TBL, is 125 percent of a representative spot market index value, which would be appropriate to use in this case as well. Penalty revenues above BPA's costs could be used to reduce BPA's cost to provide reserves for customers relying on BPA for that service.

If BPA is forced to declare a hydro emergency to provide the power because, for instance, a sufficient supply cannot be provided by the spot market, the costs of insufficiency will be imposed on external parties, fish and fish-related interests, as well as on the inadequate entity. In this case, the tariff penalty should be steeper. For instance, it could be set at 150 percent of the market price during those hours. Moreover, the revenues collected would be used for incremental fish improvements, such as the following: purchase of land, water and reduced irrigation from willing sellers; grants to non-profit habitat restoration groups such as the Oregon and the Washington Water Trusts, the Bonneville Environmental Foundation, For Sake of the Salmon, etc; grants to CBFWA, state and tribal natural resource agencies for incremental measures above and beyond current plans.

IOUs would face market prices along with whatever rate treatment their PUCs ordered for them.

PROS

- Allows responsible parties to make independent decisions and costs of decisions fall on those making the decisions
- Does not require additional mechanisms for implementation, other than minor modifications to those already in place.

CONS

- May encourage risk-taking behavior by those unable to afford the consequences.
- May be seen as encouraging free rider behavior, particularly if price caps are in place and affecting the level of market prices.
- May result in an actual insufficiency of resources to "keep the lights on" since transparency and the threat of high prices alone may be insufficient to provide incentives for new infrastructure construction.

Alternative 2a: Binding Provisions In Bonneville Power Sales Contracts and Binding PUC-IOU Processes

This alternative consists of:

- BPA incorporating binding provisions in its 20-year Power Sales Contracts (PSCs) to ensure that BPA and its public customers procure sufficient resources to meet their load obligations consistent with the regional resource adequacy metrics and targets; and
- The PUCs and IOUs in the PNW Region agreeing to binding processes that ensure the IOUs procure sufficient resources to meet their load obligations consistent with the regional resource adequacy metrics and targets.

Under this alternative, BPA's PSCs would include the provisions below in the contracts of all preference power customers with the exception of its full requirements customers. BPA would take on the responsibility of securing sufficient resources to meet the load obligations of its full requirements customers consistent with the regional and individual resource adequacy metrics and targets:

- Except for the full requirements customers, all customers would be required to report their load forecasts, firm resources, future firm resources and unspecified resources (not to exceed their "allotment" of the "planning adjustment" and uncommitted within-Region market resources) for a specified planning horizon—perhaps 1 to 10 years out. Firm resources are defined by the Forum, but can include both generation and demand-side management resources.

- BPA would perform an assessment of loads and resources consistent with the agreed-upon individual metrics and targets, i.e. an annual energy load resource balance and some type of sustained peaking capacity analysis for the planning horizon.
- If the assessments show a customer, or a set of customers, to have insufficient resources to meet their load obligations under the RA metrics and targets for the timeframe consisting of the planning year (e.g. 3 years out) to the present, this would trigger a potential action on the part of BPA to secure resources to meet this insufficiency.
- The potential BPA action would only be translated into an actual procurement action, if the NWPCC's Regional assessment also showed the Region to have insufficient resources to meet load consistent with the Regional RA metrics and targets.
- If BPA did take an action to procure resources or planning reserves, then it would have a rate mechanism in place requiring those customers with insufficient resources to meet the individual utility RA metrics and targets to pay for the resources/planning reserves.

In a similar manner, the PUCs would agree to collect the same type of data from the IOUs under their purview as BPA collects under the terms of the PSCs. The PUCs would perform similar resource adequacy assessments using the individual utility RA metrics and targets. The PUCs would agree to take actions using their established processes to ensure the utilities under their jurisdiction procured additional resources if both the PUC assessments and the NWPCC's regional resource adequacy assessment showed deficiencies in resources for the planning year, or a nearer term timeframe. One model for this approach is the requirements imposed on the California IOUs by the California PUC.

PROS

- This alternative has mechanisms designed to ensure the Region is never deficit in resources to meet the Regional RA metrics and targets
- Free ridership is minimized under this alternative

CONS

- Public utilities, IOUs and/or PUCS might consider the reporting provisions and the mandatory procurement actions potentially triggered by the RA assessments as onerous
- BPA and the PUCs would likely need additional staff to follow through on the reporting, assessment and possible procurement action processes
- This alternative may be inconsistent with the PNW RA Steering Committee's Fourth Principle "Don't trample on the jurisdiction of states or prerogatives of individual utilities in planning and acquiring resources to meet load."

Alternative 2b: Some Regional Entity Takes on the Task of Providing Adequacy Reserves

A further expansion of this approach contemplates a separate regional entity with the responsibility for procuring adequate planning reserves.

Alternative 1 proposed that load serving entities will either build the resources they need or will buy them, as shares of newly constructed power plants, through long-term contracts or through spot-market purchases. This has assumed that our data gathering will enable us to know at an aggregate level when new resources are needed in the region as a whole and in a modest way which utilities are a risk of not having enough resources to meet their loads and should be acquiring resources beyond the ones they already have.

However, there are often points in time, when individual utilities are approaching the limits of their own resources but do not quite find it cost effective to make big capital investments and would make purchases if they knew they could rely upon them as bridge until such time as the capital investments made sense. If many utilities are at this point at the same time, it is possible that none will find it advantageous to build or buy long term, thus causing the region (and each of them) to come to the brink of inadequacy. This is where a designated regional reserve might help.

An entity—a large utility, public or IOU, a consortium of utilities, BPA, a current IPP, or some new entity—would acquire (either through long-term contracts or by building generation) some amount of energy (and/or capacity??) to enable it to enter into short-term contracts (two years or less??) with those utilities who need such contracts until they acquire long term resources.

Who would pay for the reserve? Possibilities include:

- Utilities who want to access the Reserve could pay an option fee up-front which would give them rights to purchase power later. (One form of insurance)
- Utilities who want to access the Reserve could pay for a certain amount of generation to be built or acquired on their behalf which they could later receive if they need it or resell if they don't. (Another form of insurance)
- (Less likely) A governmental entity could be created which would, through some mechanism, "tax" all load serving entities and use the proceeds to maintain a regional short-term reserve which would provide power at high prices if a utility fell short.

PROS

- Centralizes adequacy reserve procurement and minimizes potential for over-building, taking into account the lumpiness of some resources (other than contracts)

CONS

- The existence of a reserve might provide an incentive for utilities to delay or avoid investing even though it would be more costly.
- Too expensive.
- Not enough interest to make it economically viable.
- What happens if reserve entity fails? Same problem as if an insurer fails without a re-insurer to back it up. If safeguards are constructed at the front end (use financially sound existing entity, don't go forward unless enough money is forthcoming, etc.), this problem can be surmounted.
- Without the (unlikely) "tax" envisioned in the third bullet (if that approach is chosen), the proposal provides no assurance that utilities would either self-provide or avail themselves of the optional Reserve described in the proposal.

Alternative 2c: Voluntary Contracts among Utilities or Control Areas and an Oversight Entity Similar to WECC's RMS Agreements

This alternative borrows the concept of WECC's Reliability Management System (RMS) and proposes to apply it to the utilities or control areas of the Pacific Northwest for the purpose of ensuring resource adequacy in the planning year and going forward. The following paragraph provides a brief description of WECC's RMS.

In 1999, the WSCC (predecessor to WECC) filed to request FERC approval of the RMS. Following is a quote from that filing: "In a competitive electric industry, the rules of the road which govern all market participants should be clear, and applied uniformly and comparably. To maintain compliance, some form of mandatory reliability management system is needed. To maintain equity and comparability and to resolve disputes, review by an agency such as this Commission is also needed." The RMS, which was implemented in three phases to thoroughly test the concept, is comprised of agreements voluntarily entered into by the transmission operators and generators, which contain "contractual obligations to comply with WSCC reliability criteria…All such contractual agreements (for transmission operators subject to Commission jurisdiction under sections 205 and 206 of the Federal Power Act ("FPA")) … (are) filed with the Commission."

Under this alternative, some oversight entity would enter into agreements with the Region's utilities or control areas to meet the individual utility RA metric and target, particularly in situations when a Planning Year regional RA assessment indicates the possibility of insufficient resources to meet the regional RA metric and target. This entity would perform RA assessments and potentially impose sanctions, if the results of the regional <u>and</u> individual utility assessments indicated resource deficiencies. Utilities or control areas would voluntarily enter into these agreements; however, there would certainly be peer pressure to do so. Although WECC's RMS agreements include monetary sanctions for violations, the sanctions associated with the PNW agreements could be limited to a public disclosure of the results of assessments showing insufficiencies.

PROS

- This alternative has mechanisms designed to ensure the Region is never deficit in resources to meet the Regional RA metrics and targets
- Free ridership is minimized under this alternative

CONS

- This alternative may be inconsistent with the PNW RA Steering Committee's Fourth Principle "Don't trample on the jurisdiction of states or prerogatives of individual utilities in planning and acquiring resources to meet load."

Alternative 3: Rely On Implementation Through Control Areas

Control areas are ultimately responsible for electric system reliability. While control area focus centers on short-term reliability, control areas have access to the information contained in the region's Resource Adequacy assessment affecting their area of regional responsibility. From an electric system point of view, control areas meter the total load in their area (regardless of what load-serving entity is supplying it), the amount of generation available in their control area (regardless of who is buying it), as well as the amount of firm imports and exports entering / leaving their control area.[7] These reliability parameters can be determined through the use of NERC tags that identify the generation source control area, the amount and quality of power available from the generator (firm, interruptible), the amount and quality of transmission associated with the transaction (firm / interruptible),[8] as well as the control area that contains the commercial "sink" for the transaction. Thus, control areas are best positioned to measure the amount of market resources and net out-of region surpluses affecting their area of responsibility.

These responsibilities could be extended to include forecasting to meet a resource adequacy metric and target from a planning perspective. In the event of forecasted resource inadequacy (which would imply an inability to meet load obligations and provide required "planning" reserves during that time frame), the control area could contract for "planning reserves" in advance from generation (or interruptible load) located within its control area, from control areas that are forecasted to be "long," due to uncommitted generation, or from out-of-region generation over firm transmission paths. These contracts for planning reserves would differ from the existing WSPP Schedule C product in that they would be tied to specific generation units and transmission paths, require sufficient operating reserves such that within-hour curtailments would not occur, and that a failure to deliver over the contract term would not be permissible under a *force majeure* condition.

[7] Control areas require that firm imports into the control area be supported by appropriate operating reserves, that interruptible imports carry a 100% operating reserve available to the control area, and that firm exports from the control area have arranged for necessary operating reserves from the control area.
[8] Power system operators note that some interruptible paths have proven more reliable than some firm paths.

A potential conflict is noted between these new control area responsibilities and the current role of utility merchant / power planning functions operating under a utility's Integrated Resource Plan. The intent proposed in this approach is to formally tie actions taken by such groups to the adequacy of planning reserves available to the control area. To the extent that the "merchant" or power planning group affiliated with a control area develops sufficient resource or firm purchases, these resources would be noted by the control area and would count towards providing sufficient "resource adequacy." To the extent that the Integrated Resource Plans of such groups implement a deliberate strategy to be "short" of firm resources and instead specifies a reliance on non-specific market purchases, the control area would note such potential shortages and determine "resource adequacy" accordingly. If other control areas were "long" during this timeframe, overall resource adequacy may be maintained. However, this approach would more clearly identify the need to allocate the uncommitted intra-regional market and "planning adjustment" resources among the region's control areas during timeframes when one or more may be "short."

In addition to providing a clearer picture of within-region market resources and net out-of-region surpluses, the implementation of resource adequacy standards through control areas has the additional advantage of inclusion. Not only would the region's utilities and IPPs be accounted for, but the availability of resources needed by other load-serving entities such as power marketers serving retail load would be accounted for as well. Entities that are not signatories to a BPA Power Sales Contract would still be responsible for ensuring resource adequacy through their control area requirements. This approach would capture the region's investor-owned utilities as well as publicly owned utilities that operate their own control areas or fall within the purview of the BPA control area.

The ultimate cost of ensuring resource adequacy would continue to be borne by the region's retail electric customers. Control area costs are allocated through the transmission rates of control area customers, who in turn pass along such costs to end-use customers. Thus, the approach suggested above is not intended to side-step the allocation of costs through the region's load-serving utilities, but is instead intended to implement resource adequacy in the most efficient and cost-effective manner possible.

PROS

- Continued implementation of NERC standards and WECC reliability responsibilities through those entities currently responsible for maintaining reliability standards;
- Providing a "bridge" from the current control area administration of reliability to a more centralized "Reliability Authority" structure envisioned in NERC's "Functional Model;
- Administration of Resource Adequacy Standards among a comprehensive set of market participants;
- Consistent implementation of Resource Adequacy Standards through the control areas of the publicly-owned and investor-owned utility sectors;

- Maintaining the commercial relationship and obligations between BPA and its publicly owned utility customers in the new 20-year Power Sales Contracts.

CONS

- Expansion of control area responsibilities over a longer-term time horizon;
- Role confusion between control areas and the utility merchant / power supply group responsibility to build/procure/operate resources under Integrated Resource Plans;
- Control areas are undergoing a transformation towards NERC defined "functional" model and may become obsolete in the future;

APPENDIX
Background on Control Areas and on Bonneville Contracts

Reliability and Control Areas

The introduction to the NERC Reliability Functional Model states the following:

"Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customer's electricity needs. The traditional Control Area operator balances its load with its generation, implements interchange schedules with other Control Areas, and ensures transmission reliability.

"As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC's Operating Policies and Standards have reflected this traditional electric utility industry structure, and ***ascribed virtually every reliability function to the control area."*** *(emphasis added)*

National energy policy has since lead to the separation of "commercial" and "reliability" industry functions. Reliability services, such as the provision of spinning and operating reserves, voltage / VAR regulation, black-start capability, … , have been separately identified and have become the responsibility of grid operators under their Open Access Transmission Tariffs (OATTs). In the Pacific Northwest, these grid operators take the form of "control areas" that manage the generation and transmission of electricity among entities that are electrically interconnected, telemetered, and bound by contracts with the control area to operate under specified parameters.

While national energy policy is disaggregating control area responsibilities through development of a "functional model,"[9] and is moving towards the consolidation of control areas into regional reliability organizations, the Pacific Northwest is home to seventeen separate control areas. These entities are responsible for compliance with NERC standards and WECC Minimum Operating Criteria (MORC), face penalties for non-compliance, and would respond to an actual power emergency brought about through a shortage of power resources. These control areas are members of the Northwest Power Pool (NWPP) and participate in the reserve-sharing program administered by the NWPP.

Control areas in the Pacific Northwest are operated by the Bonneville Power Administration (BPA), investor-owned utilities, as well as some publicly-owned utilities. While the BPA is the largest control-area entity and provides control area services for most of the region's publicly-owned utilities, not all of BPA customers operate within

[9] The "NERC Reliability Functional Model" explicitly outlines the resource adequacy responsibilities through Planning Reliability (p. 14), Resource Planning (p. 22), and Transmission Planning (p. 28).

BPA's control area.[10] In addition, some control areas may provide a subset of control area services, such as operating and spinning reserves, to entities that are within another entities control area.[11]

Commercial Relationships Between BPA and its Customers

Under the Regional Power Act, BPA is required to provide requirements service to the region's publicly-owned and investor-owned utilities upon request.[12] Request for service from the region's investor-owned utilities would be provided under rates established through Section 7(f) of the Regional Act, while publicly-owned "preference" customers receive service under rates specified in Section 7(b). In general, the region's publicly-owned utilities have priority rights to the firm power available through existing Federal Base System resources.

No investor-owned utility currently holds a Requirements Purchase Power Agreement with BPA. However, each investor-owned utility has a Settlement Agreement related to the Residential Exchange Program. PGE is currently taking approx 259 aMW of firm power under its Settlement Agreement. All other investor-owned utilities, including PacifiCorp, sold their firm power back to BPA.

Not all publicly-owned utilities have requested or are entitled to receive requirements service from BPA. The mid-Columbia utilities of Chelan PUD and Douglas PUD have sufficient resources available to them from federally licensed dams on the Columbia River and have not entered into Power Sales Contracts with BPA. However, these utilities are still required to operate under NERC standards and WECC reliability criteria, and currently operate their own independent control areas to so comply.

Other publicly-owned utilities operate independent control areas and can choose to request service from BPA through wholesale Power Sales Contracts. Examples include Grant PUD, Seattle City Light, and Tacoma Power. These purchases are not made for reliability purposes, but as an economical choice of power supply from among a host of alternative power suppliers and resources.

Some of BPA's publicly-owned utility customers operate their own non-federal power resources and have access to wholesale power markets, yet have chosen not to form and operate independent control areas.[13] These utilities have contractual relationships with BPA's Transmission Business Line that specify the interconnection, scheduling, and reliability requirements within which these utilities must operate. Thus, BPA is

[10] E.g., Chelan PUD, Douglas PUD (also the control area for Okanogan PUD), Grant PUD, Pend Oreille (in Avista control area), Tacoma Power, Seattle City Light

[11] For example, EWEB contracts with the Seattle City Light control area to provide operating reserves to BPA in the event EWEB requires them.

[12] "Requirements service" is generally the difference between a utility's retail load obligations and a set of resources that have been "declared" as available to meet retail load.

[13] Examples include Benton, Franklin, and Gray's Harbor PUDs, EWEB, PNGC, Snohomish, and others.

responsible for providing reliability services to these utilities, with this responsibility administered through BPA's control area embodied in the Transmission Business Line.

As if the previous dichotomies among BPA's retail customers are not confusing enough, not all of the retail load contained within BPA's control area is provided by utilities. While most of the region's retail load is served through publicly-owned or investor-owned utilities, other "load serving entities" include retail marketers. These load-serving entities have not signed Power Sales Contracts with BPA, but are required to operate within reliability criteria established through BPA's OATT administered through the control area functions of BPA's Transmission Business Line.

In addition, independent power producers (IPPs) and industries with on-site generation are connected to and operate within the region's control areas, including BPA. While the commercial disposition of output from these entities is highly case specific, interconnection agreements with associated control areas specify reliability criteria applicable to non-utility generator operation.

Identification of Resources Under Existing BPA Power Sales Contracts

BPA offers four major categories of Power Sales Contracts to its publicly-owned utility customers:

- Full Requirements Contract
- Partial Requirements Contract
- Block Contract
- Slice/Block Contract

Each contract has requirements for the identification of non-federal resources (if any) used to meet the customer's load.

Under a Full Requirements Contract, the customer either has no non-federal resources or whatever non-federal resources at its disposal are so small as to be administered on an "as available" basis to meet the customer's retail load requirement. A Full Requirements Customer cannot schedule power to / from its system to meet load independently from non-BPA sources. Hour-by-hour fluctuations in load are met by BPA, as well as any load growth that may occur on the customer's system over the life of the Full Requirements Contract.

A Partial Requirements Customer has access to non-federal resources as well as market purchases. A Partial Requirements customer may also be a purchaser of BPA's Pre-subscription Products. Cowlitz PUD and the Springfield Utility Board are examples of a Partial Requirements Customer of BPA. These customers are required to identify resources anticipated to serve their retail load, and are entitled to receive BPA power to meet the difference between their actual retail load and the specified amount of energy identified as being available from non-federal resources or purchases. BPA is contractually obligated to meet hour-by-hour variations in the customer's power supply needs, as well as to provide service to the customer's load growth that may occur over the life of the Partial Requirements Contract. However, the customer may choose to provide additional new resources to serve its retail load. In such an event, minimum notice provisions must be met under the terms of the Partial Requirements Contract.

In contrast to the Full and Partial Requirements Contracts, whereby BPA is obligated to meet a customer's hour-by-hour load variations as well as any long-term load growth, BPA does not provide these services to Block or Slice/Block Contract customers.[14] A Block Contract simply provides for the sale of specified "blocks" of electricity. These blocks are contractually described on both a monthly and heavy-load / light-load hour basis. A Block Customers uses resources that are specified in the BPA Power Sales Contract to meet its overall load requirements on both an annual as well as on an hour-by-hour basis. Examples include Grant County PUD and Tacoma Power, both of whom operate their own independent control areas.

Slice / Block customers receive a block of power from BPA, but also receive a specified percentage of the output and capability of BPA's Federal Base System resources. Examples include Benton PUD, Clatskanie PUD, Eugene Water & Electric Board, Franklin PUD, Gray's Harbor PUD, City of Idaho Falls, utilities of the Pacific Northwest Generating Cooperative, Seattle City Light, and Snohomish PUD. As the output of BPA's FBS resources varies with stream-flow and other conditions, it is not generated in a shape that matches the load requirements of these customers. Slice / Block customers must meet hour-by-hour load variations, monthly energy deficits, as well as annual load growth through alternative resources and/or power purchases.

BPA's Power Sales Contracts require customers (other than Full Requirements Customers) to identify resources that they intend to use to meet forecasted retail load, as well as to provide updated load forecasts on an annual basis. Resources include those that were used to meet retail load prior to the passage of the Regional Act, the output of which is to be used in serving retail load requirements.[15] Additional resources that must be identified consist of "unspecified resource amounts committed to serve total retail load" to balance Net Requirements due to a mismatch in load/resource shape or due to load growth.

[14] While some might argue that BPA has a statutory "obligation to serve," Block and Slice/Block customers have contractually committed to meet their load growth during the duration of these contracts.
[15] Such resource output can be "lost" under specified contract conditions, in which case the utility may receive additional entitlement to BPA power.

The following table provides an illustrative view of the control area and Power Sales Contract relationships of various regional entities and BPA:

Entity	Independent Control Area	BPA Requirements Power Sales Contract	Independent Resource Ownership
Investor-owned Utilities			
Avista Corp	Yes	No	Yes
Idaho Power Company	Yes	No	Yes
PacifiCorp	Yes	No	Yes
Portland General Electric	Yes	No	Yes
Puget Sound Energy	Yes	No	Yes
Northwestern Energy	Yes	No	No
Publicly-owned Utilities			
Benton PUD	No	Slice / Block	Yes
Clatskanie PUD	No	Slice / Block	Yes
Chelan PUD	Yes	None	Yes
Cowlitz PUD	No	Partial Requirements	Yes
Douglass PUD	Yes	None	Yes
Eugene Water & Electric Board	No	Slice / Block	Yes
Emerald PUD	No	Full Requirements	Yes
Franklin PUD	No	Slice / Block	Yes
Grant PUD	Yes	Block	Yes
Idaho Falls	No	Slice / Block	Yes
Pacific Northwest Generating Cooperative	No	Slice / Block	Yes
Pend Oreille PUD	No	Slice / Block	Yes
Seattle City Light	Yes	Slice / Block	Yes
Springfield Utility Board	No	Partial Requirements	Yes
Snohomish PUD	No	Slice / Block	Yes
Tacoma Power	Yes	Block	Yes

Service under "Tier Two" Provisions of New 20-Year BPA Power Sales Contracts

BPA and its customers anticipate allocating the capability of existing Federal Base System resources among BPA's publicly owned utility customers. Under this scenario, BPA would maintain its legal obligation to provide service to eligible customers. However, service would only be provided upon specific request, and the cost of such service would be borne directly by those who request it. This in effect leads to "tiered" service to customers from BPA, with the "first tier" coming from FBS resources at the costs of these resources, and the "second tier" service coming from additional power supplies acquired by BPA at the request of those customers desiring such service. The cost of “tier two” service would be based on BPA’s incremental cost incurred to provide such service, and would not be “melded” with the costs of FBS resources used to provide service through “tier one” service.

While the details of “tier two” service have not yet been determined, BPA must address certain commercial issues that ensure BPA will have timely access to necessary resources and can fully recover its costs incurred to provide tier two service; BPA is not being asked to provide a “free option” to its customers through the tiered rate mechanism. BPA has accomplished these objectives in the past by requiring timely notice to BPA that a customer is requesting service,[16] and has also implemented targeted cost recovery provisions (TACUL) that would enable BPA to recover incremental purchase power costs not anticipated in setting its otherwise applicable rates.[17] Such protections seem commercially reasonable to ensure full recovery of BPA costs incurred in providing wholesale electricity to its requesting customers, regardless of resource adequacy issues. This approach is also compatible with the policy intent of tiered rates, whereby those requesting service from BPA above a pre-established level would be fully responsible for the costs of such service.

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[16] Previous contracts have required notice provisions of up to five-to-seven years before BPA was obligated to provide service.
[17] Sales made by BPA prior to the implementation of the 2001 Power Sales Contract through the “targeted adjustment clause” (TACUL) provisions arising from the 199? rate case.