IRP Practitioners' Responses -- 1	
Under what authority or requirement do you do your IRP?	
Avista	WUTC/IPUC
BC Hydro	
BPA	The Bonneville Power Administration (BPA), as a Federal Power Market Agency, is not required to prepare an IRP. The Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839 et seq., which was enacted December 5, 1980, created a regional planning authority. In its White Book, BPA performs both a regional and BPA load/resource balance. The inventory documented in the White Book is a key input to BPA's power rate cases. BPA's power rate cases, in some ways, resemble an IRP. The power rate cases specify, in detail, BPA's augmentation requirements to ensure that BPA's load obligations will be served, consistent with the NWPPC's regional power plan, which is currently in effect.
Eugene	Under Oregon law, EWEB has authority to undertake any planning, rate making, or other resource related decisions under the auspices of its own elected five-member board. The 1992 National Energy Policy Act (92NEPA) required publicly owned utilities with annual sales of 500 million kWh or greater, to hold a public hearing at which integrated resource planning was considered. The utility then had to proceed with such planning or state why not. EWEB had just completed it's first IRP process so met the legal requirement.
Idaho Power	Both the Idaho Public Utility Commission and Oregon Public Utility Commission require Idaho Power to file an integrated resource plan.
Northwestern	
PacifiCorp	PacifiCorp is required to file an IRP or Least-Cost Plan in four states in which it operates. The following are the orders, dockets and rules related to IRP or least-cost planning with which PacifiCorp must comply: Oregon – Order 89-507, Utah – Docket 90-2035-01, Washington – WAC 480-100-251, and Idaho – Order 22299
PGE	
PNGC	There is no formal or legal requirement. If we do one it is voluntary.
PSE	Puget Sound Energy (PSE) is required to prepare Least Cost Plans in compliance with requirements set forth in WAC 480-100-238 (electric) and WAC 480-90-238 (natural gas).
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	The IRP is formally presented to the Tacoma Public Utility Board. The IRP is not specifically required by resolution, but serves as an effective means of quantifying the organizations overall supply strategy including future supply acquisitions. It also serves as an effective tool for communication with the Public Utility Board.
NWPPC	The Pacific Northwest Electric Power Planning and Conservation Act of 1980

IRP Practitioners' Responses -- 2	
How frequently (e.g. every two years, every five years)?	
Avista	Every 2
BC Hydro	
BPA	BPA generally updates its White Book on an annual basis. BPA's power rate cases are undertaken on a regular rate case schedule, sometimes as often as 2 years. The current rate case covers a six-year period, but has provisions for cost recovery adjustment clauses.
Eugene	EWEB has conducted IRP or similar work going back to the early 80's. We redo or update the plan as time or conditions warrant, typically every four years or so. We also update forecasts and planning assumptions on a more frequent schedule as we make resource allocation decisions.
Idaho Power	Idaho Power is required to file integrated resource plans every two years.
Northwestern	
PacifiCorp	PacifiCorp is required to file its IRP biennially.
PGE	
PNGC	There is no set frequency
PSE	PSE is required to prepare a new Least Cost Plan on a biennial basis.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	There is no set calendar timeline as to how often the IRP is produced or updated. Instead, Tacoma utilizes an internal IRP planning team to monitor signposts and make recommendations as to the timing and nature of updates. In practice, updates are generally made at least 2 times per year in preparation for formal presentation to the Public Utility Board. The IRP is essentially looked upon as a "living" document.
NWPPC	Three to five years. Plan must be reviewed at least every five years. Components of the plan, e.g., fuel price forecasts, are updated as necessary and are used as indicators of whether a complete plan revision is called for.

IRP Practitioners' Responses -- 3	
What is the plan's time horizon (e.g. 5,10, 20 years)?	
Avista	Generally 20 years, but 2001 plan was 10 years
BC Hydro	
BPA	BPA's White Book has a 10-year horizon. The horizon for BPA's rate cases vary, depending on the timeframe for which the rates are in effect.
Eugene	20 years
Idaho Power	Idaho Power files a 10-year plan in Idaho and Oregon.
Northwestern	
PacifiCorp	PacifiCorp is required to file a 20-year plan, with a short-term (2-4 year) action plan.
PGE	
PNGC	In our next IRP we will go out 15-20 years
PSE	The planning horizon is 20 years, with a two-year Action Plan.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	20 Years
NWPPC	The plan has a twenty-year horizon but much of the focus is on a five-year action plan.

IRP Practitioners' Responses -- 4	
What regulatory or governance action is take in response to plan?	
Avista	Public notice and sometimes hearings. Commissions "acknowledge" that the plan meets certain rules and standards
BC Hydro	
BPA	BPA's Power Sales Contracts and Rate Cases generally address the issue of augmentation. Both the contractual and record of decision instruments may describe at a high-level augmentation principles, but, in practice, provide BPA a fair amount of latitude in the types and amounts of conservation and generating resources to procure to ensure load/resource balance.
Eugene	Action plans in the four or five major resource areas (renewables, dsm, centralized generation, power purchases, and distributed resources) are updated and workplans and anticipated expenditures become part of the annual budget process. .
Idaho Power	The plan is acknowledged by the Commissions if found to comply with standards, guidelines and rules related to dockets, orders and rules.
Northwestern	
PacifiCorp	The IRP is *acknowledged* by the Commissions if found to comply with standards, guidelines and rules related to dockets, orders and rules listed above for each of the states in which an IRP is required. It is important to note that the acknowledgement does not guarantee favorable rate-making, and prudency reviews of new resource acquisitions will occur during rate making proceedings.
PGE	
PNGC	See No. 1.
PSE	The Least Cost Plan is reviewed by the Washington Utilities and Transportation Commission (WUTC) and if found to meet the prescribed requirements, the plan is "accepted" by the WUTC.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	The plan is formally presented to the Public Utility Board. The board acknowledges the plan and in some cases formally adopts it (formal adoption of the plan is a necessary step in the process of making a supply acquisition).
NWPPC	The plan is adopted by the Council after public review in each of the states. Once adopted, Bonneville's acquisition of "major resources" (>50 MW for > 5 years) must be found to be consistent with the Council's plan or specific authorization must be given by Congress. There have been few acquisitions of major resources.

IRP Practitioners' Responses -- 5	
How recently have you done or will you be doing an IRP?	
Avista	We just filed our 2003 plan (April 30th)
BC Hydro	
BPA	The NWPPC's Fifth Power Plan is in the process of being developed. BPA and the NWPPC have initiated a Regional Dialogue on BPA's future role in power supply. The outcome of that process will determine whether BPA's power supply footprint is substantially limited to marketing the output of the FBS, or whether BPA has a more, or less limited role, in augmenting FBS resources to meet its load obligations post 2006. A key objective of that process is to provide clarity in terms of load serving obligation both to BPA and the Region's Load Serving Entities (LSEs).
Eugene	The most recent plan was completed in November 1999. We are just beginning an update process now to be completed in about a year.
Idaho Power	Our last IRP was filed in June 2002. Idaho Power will file a new plan in June 2004.
Northwestern	
PacifiCorp	PacifiCorp's latest IRP was filed with the State Commissions in January 2003. PacifiCorp will be providing an updated Action Plan to the Commissions in October 2003.
PGE	
PNGC	Our last IRP was done in 1994. There is no firm plan for a new one.
PSE	PSE submitted its latest Least Cost Plan to the WUTC on April 30, 2003.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	Tacoma completed its last IRP one year ago. Updates to the plan have been made since that time.
NWPPC	Currently in the process of developing the Council's fifth plan.

IRP Practitioners' Responses -- 6	
Does your plan incorporate a planning reserve and how was it chosen?	
Avista	No, at least not in the sense of what many would define as a planning reserve margin. We for this plan focused on meeting our energy requirements at an 80% confidence level. We expect that our next plan will consider planning reserve margins. We did calculate planning reserve margins and have levels above 12% through 2009.
BC Hydro	
BPA	BPA's augmentation strategy is based on a critical hydro inventory analysis that incorporates operating reserve requirements and accounts for transmission losses. Rather than using a capacity planning reserve, as many thermal-based utilities do, BPA considers planning to critical hydro on an annual basis sufficiently conservative to balance costs and risks. BPA's "A Guide to Tools and Principles for a Dry Year Strategy" describes tools that BPA can use to address situations when loads are projected to exceed FBS and contracted for resources.
Eugene	In the past we have relied on the various control areas for providing traditional operating reserves. The broader notion of "planning reserves" is to be addressed in our current IRP process. At this point we believe that "adequacy" is a control area issue in the sense that the control area, or RTO, has official system reliability responsibilities.
Idaho Power	Idaho Power plans to meet WECC criteria for reserves. The current requirement is for Idaho Power to maintain 330 MW of reserves above the forecast peak load to cover an unexpected loss equal to Idaho Power's share of two Bridger generation units. Roughly 9% of Idaho Power's peak demand.
Northwestern	
PacifiCorp	The portfolios analyzed in PacifiCorp's IRP were built to meet a 15% Planning Margin. The 15% planning margin was used to provide sufficient resources to cover forced outages, provide operating reserves, regulatory margin, and demand growth uncertainty. PacifiCorp used the following calculation to determine planning margin requirements: 15% Planning Margin = (Coincident Peak Load + Firm Sales – Firm Purchases – Interruptible Load)*15%. The planning margin was selected based on what PacifiCorp thought was a reasonable proxy for FERC's Standard Market Design proposal related to resource adequacy. FERC proposes that all load-serving entities meet a capacity reserve planning margin of between 12 – 18%. PacifiCorp has committed to reviewing the planning margin assumption and has in it's action plan an action item (#24) to determine the planning margin PacifiCorp will adopt if different from the 15% planning margin used in this IRP. Further analysis of trade-offs between more or less planning margin and operational stability and risk will be performed. We will also monitor and participate in both federal (SMD) and regional resource adequacy discussions in order to gain a better understanding of possible future requirements.
PGE	
PNGC	Our last plan did not use a planning reserve. In the future this may be an issue
PSE	For its April 30, 2003 Least Cost Plan, PSE did not start with a prescribed planning reserve. Instead, we evaluated a range of different levels of long-term firm resource adequacy to serve monthly energy loads and to serve winter peak hour loads. The evaluation included modeling of resource portfolios that were "built" to satisfy each level of resource adequacy. The analysis focused on expected cost, variability of cost (i.e., risk), amounts of market purchases and sales of power associated with each level of resource adequacy. Other factors, including Guiding Principles from the Washington State Energy Strategy, were also considered in determining the level of resource adequacy. As a result of the analysis and application of judgment, PSE selected a balanced portfolio approach that would provide resources sufficient to serve customer (a) energy needs in all months under average hydro conditions, and (b) peak loads on winter days that the minimum hour temperature at Sea-Tac airport drops as low as 16 degrees

	Fahrenheit.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	Tacoma plans to critical hydro conditions with respect to average energy and peak loads.
NWPPC	We do not plan to a reserve margin. Prior plans developed "resource strategies," which provided low-cost flexibility to respond to anticipated need for energy under critical water. Similarly the fifth plan will identify a least-cost resource plan that provides flexibility under uncertainty and that limits cost exposure (risk).

IRP Practitioners' Responses --7	
What do you assume with regard electricity market depth and liquidity?	
Avista	We do not limit the depth and liquidity, but we do focus on the inherent risk of being forced to rely too much on market purchases to meet load requirements. We instead consider the marketplace an opportunity to optimize our resource operations and ensure we have adequate generating capability to have the option of staying out of the market in times of extreme volatility.
BC Hydro	
BPA	Estimates of electricity market depth and liquidity influence within year buy-sell decisions as well as the timing and rate of augmentation power purchases.
Eugene	Because of our size we have usually assumed that the market has sufficient depth and liquidity – though the number of credit worthy counterparties has slimmed significantly. EWEB's assumptions regarding depth and liquidity are driven by regional forecasts of available surplus, coupled with day-to-day experience in our wholesale purchase/sales activities. On a planning basis EWEB is comfortable relying on unspecified market purchases during periods the PNW is forecast to have available resources. EWEB utilizes the NWPPC forecasts, NWPP summer/winter outlook, and to some extent, PNUCC forecasts over a two-year horizon to make this determination. If EWEB is experiencing problems with liquidity in some markets, future reliance on these markets is diminiished on a planning basis. For example, we are less comfortable relying on market purchases in 2006 than we are in 2004, based on availability of power supplies in these timeframes from creditworthy counterparties today.
Idaho Power	While there are specific measurements that we use to quantify market depth and liquidity, Idaho Power assumes that the Mid-C market has more depth and liquidity than markets to the east and south of our control area.
Northwestern	
PacifiCorp	Market depth and liquidity limitations constrain PacifiCorp's ability to balance its system in the market at a reasonable cost. Liquidity costs and limitations are observed in the bid-ask spread, price impacts or 'slippage' and other trading functions. Estimations of future liquidity are difficult and somewhat subjective. Such frictions vary by market hub, lead-time and the size of the position to clear. Building to a 15% margin over the forecasted peak requirement, PacifiCorp has substantial balancing requirements in non-peak periods. To capture the known but subjectively defined frictions associated with market liquidity, PacifiCorp's market access (both sales and purchases) is capped as follows:- 250 MW at COB,- 250 MW at Mid-Columbia, and- 500 MW at Palo Verde. Such limits help deter impractical model dispatch decisions and appear consistent with historical practice. All market transactions outside of existing long-term contracts are subject to this limitation. In addition to this market limitation, all portfolios in the IRP were designed to limit expected spot purchases to 5% or less of each year's hours. The 5% limitation provides intuitive benefits associated with power price volatility.
PGE	
PNGC	N/A
PSE	PSE paid extensive attention to power market depth and liquidity in its April 30, 2003 Least Cost Plan. This included a review of recent developments in the merchant generation sector and development of market price scenarios that address potential consequences of the problems that merchant developers are now experiencing. In addition, PSE identified and assessed the importance of the relationship between utility decisions about their own level of resource adequacy and the overall regional level of resource adequacy. We also identified risks associated with basing utility resource plans on market power price forecasts produced using forecasting models that assume continuous market equilibrium (aka market liquidity) and

	perfect foresight by resource developers (aka market depth).
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	With respect to IRP planning, Tacoma generally does not explicitly include issues of market depth and liquidity (analysis generally assumes a liquid market). However, critical water planning methodology implicitly acknowledges the potential for liquidity problems.
NWPPC	In the past, we have implicitly assumed that the market has unlimited depth and liquidity, although purchases and sells might be physically constrained, e.g. by net intertie capacity. The fifth Power Plan will address market depth and liquidity through increased bid-ask spreads in high-price market situations.

IRP Practitioners' Responses -- 8	
What performance measures does the IRP use (e.g. expected cost, rates, risk, reliability, environmental emissions)?	
Avista	Lowest cost and lowest risk are equally weighted to arrive at an "optimal" result. Environmental considerations are handled through scenarios.
BC Hydro	
BPA	Among BPA's key performance measures are its power rates and Treasury Payment Probability (TPP). The NW Power Act includes a mandate that BPA provide the Northwest with economical power, so BPA seeks to provide power at the lowest rates possible, while concurrently safeguarding fishery resources and promoting renewable energy and conservation resources. BPA is also charged with repaying the capital costs of the FCRPS in a timely manner through annual payments to the U.S. Treasury. BPA calculates TPP on a regular basis. BPA power rate cases, which are quasi-IRPs, attempt to balance BPA's objective of keeping rates as low as possible with the risk of not being able to make the annual treasury payment. The 2000 BiOp specifies numerous biological performance measures for the Columbia River fishery resources. FCRPS hydro operations are planned on an annual basis to achieve the hydro-based objectives of the 2000 BiOp in a least-cost manner.
Eugene	On the economic/financial side they have included: NPV of Total Resource Cost, NPV of Revenue Requirements, Average Annual Retail Rate, Average Household Monthly Bill, Levelized Cost of Portfolio, Annual Net Portfolio Cost compared to Market. On the non-economic side we have made estimates of CO2, NOx, and SOx emissions on both a gross annual average basis and as a per MWh value. We have also used some constructed scales for a few IRP objectives such as "flexibility" and "competitiveness".
Idaho Power	Expected costs, rates, reliability and environmental impacts are all considered when identifying least-cost resources in Idaho Power's IRP. More comprehensive risk and uncertainty analyses will be incorporated in future IRP's.
PacifiCorp	PacifiCorp used deterministic analysis to screen portfolios based on the following performance measures: - Present Value of Revenue Requirements (PVRR),- Capital Costs,- Emissions (Hg, CO_2, NO_x, and SO_x), - Market Purchases and Sales,- New and Existing Unit Capacity Factors, and - Transmission transfers between control areas. The top portfolios were then tested using stochastic analysis to simulate the performance under a large number of possible futures. The stochastic analysis was used to measure the risk associated with each of the portfolios. One hundred variations in load, natural gas and electric prices, hydrogeneration and outages were simulated in the stochastic analysis. Since all risks and uncertainties cannot be measured stochastically, stress tests were performed on the top portfolios to determine which portfolios performed best under different possible outcomes. Thirteen stress tests were performed in PacifiCorp's IRP. Some of these stress tests include, modifying the assumed value of CO2 allowances, modifying wind resource cost assumptions and capacity values, altering hydro resources to account for re-licensing impacts, changing West loads to model SB 1149 impacts, and changing the Planning Margin assumption.
PGE	
PNGC	
PSE	PSE's April 30, 2003 Least Cost Plan focused primarily on the following performance measures: *a)* expected cost to customers (20-year net present value basis)*; and b)* risk (standard deviation of expected cost to customers) exposure to market purchases and sales
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	Cost, environmental impact, resource reliability and flexibility, control, ownership and location,

	portfolio diversity, resource timing, risk/uncertainty. Rate impacts are not explicitly used at this time, but will be incorporated into future IRP analyses
NWPPC	Previously, our primary measure has been net present value societal cost. We reflected uncertainty in fuel prices, and long-term supply, and loads through probability distributions. Fish and wildlife mitigation measure are treated as a constraint. We examined emissions, cost allocation, lost opportunity resources (e.g. conservation in new buildings or equipment), and we made adjustments if appropriate. Stress-testing provided insight into risk. The fifth Power Plan will add cost risk constraints, as measured by conditional value-at-risk, and Loss of load probability (LOLP) constraints.

IRP Practitioners' Responses --9	
If risk is a performance measure, how is it defined and measured?	
Avista	Risk is measured as the standard deviation of net power supply expenses (load mark-to-market less resource value mark-to-market) over the study period.
BC Hydro	
BPA	As mentioned above, TPP is a key performance measure. By definition, TPP is the determination of the probability of being able to make the yearly treasury payment. As mentioned above, the power rate case, currently in effect, attempted to balance low rates with the risk of not meeting TPP and of not having sufficient operating revenues through the use of CRACs. For example, to keep rates as low as possible, the power rate case assumed secondary revenues from the sale of surplus power based on an average hydro year and market price assumptions that appeared reasonable in 2001. The planning of flexibility of FCRPS operations is done in such a way as to maximize secondary revenues associated with marketing of surplus generation. However, a number of factors beyond BPA's control including market prices and runoff may result in less than predicted revenues. If the risk of missing a payment becomes too high, cost-cutting measures are implemented and rates are adjusted as a last recourse.
Eugene	Risk has certainly been an area of interest since the beginning but we have not settled in on any specific performance measure to date. We have typically used some kind of comparator like how one portfolio's PVRR could be significantly higher than an alternative portfolio in the case of a high gas price scenario. For us, risk is nearly always a comparison parameter between one course of action (or inaction) and alternative courses of action. We also believe that time frames have a significant impact on decision makers' perceptions of risk. For example near-term uncertainty about natural gas prices coinciding with near-term consideration of another PNW drought attract a lot of attention while issue like long-term availability of natural gas and climate change are "discounted" both analytically and psychologically. We are exploring ways to understand and mitigate these biases.
Idaho Power	Risk is not modeled as a performance measure.
Northwestern	
PacifiCorp	Risk is observed in the variability of PVRR.
PGE	
PNGC	
PSE	Risks were addressed in several ways. The modeling analysis focused on variability of cost to customers, quantified as standard deviation of expected cost. The modeling analysis addressed this through the use of Monte Carlo simulation techniques for key uncertain variables.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	Tacoma's IRP planning reflects the risks associated with uncertainty of hydro, loads, wholesale electricity market prices and fuel prices.
NWPPC	In the last plan, the expected cost of resource strategies and the distribution of those costs were determined through monte carlo simulations with load, fuel price and hydro uncertainty. Strategies that were more robust generally demonstrated lower expected cost. In the current plan, we consider economic risk and system reliability. Economic risk is represented by the expected value of cost above a threshold, referred to as Conditional Value at Risk, or CVaR. (CVaR is analogous to the system reliability criterion, Unserved Energy.) From this perspective, risk is not the variation of Net Present Value Revenue Requirement, but an aspect of the distribution's unfavorable outcomes. Costs are minimized, subject to a constraint on risk. System reliability is measured by loss of load probability (LOLP) as the Council has done in recent (2000, 2001) reliability assessments. We are currently considering other measures of

	reliability that address the magnitude and duration of system events.

IRP Practitioners' Responses -- 10	
How is the tradeoff between risk and other performance measures addressed?	
Avista	We believe that quantitative modeling can answer many questions around integrated resource planning that traditionally have been considered "qualitative." However, the Company does still have a limited set of qualitative criteria (e.g., level of cogeneration assumed, limitation on wind to address inherent lack of capacity)
BC Hydro	
BPA	The tradeoff between risk and performance measures is formulated through public processes in the BPA's power rate case forums as well as the Regional Dialogue that is currently ongoing. For example, in the current rate case, the consensus opinion appeared to favor balancing higher risks of missing TPP with lower rates. Unfortunately, drought conditions and unfavorable market prices combined with high-priced power purchases in 2001 and high IOU Residential Benefit payments have resulted in the triggering of CRACs and the raising of power rates.
Eugene	We have used scatter plots of pairs of parameters for performance measures and sometimes assessed the "slope" value between two portfolio outcomes to get an estimate of what the implied cost of getting from one outcome to another might be. In many cases it is difficult to quantitatively describe the tradeoff between a pair of performance measures. So, often the tradeoff decision or determination is made in a deliberative policy conversation among analytical staff and management. Our Board has encouraged presentation of diverse staff viewpoints.
Idaho Power	Not applicable.
Northwestern	
PacifiCorp	The tradeoff between cost and risk was primarily presented using a scatter plot. Cost was plotted along the x-axis while a risk measure was plotted along the y-axis. Observations closer to the origin (lower cost and/or risk) were deemed superior. Also, a study of planning margin reviewed the tradeoff of cost for risk. This study compared the cost vs. risk differentials associated with a lower planning margin assumption.
PGE	
PNGC	
PSE	PSE modeled tradeoffs between expected cost and variability of cost for different levels of resource adequacy and for various technology mixes. The results of these analyses were displayed on two-dimensional scatter charts. Qualitative judgment was also applied in cases where one choice involved lower expected cost but higher risk, versus another choice that involved higher expected cost but lower risk.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	The tradeoff between risk and cost is not explicitly quantified within the current IRP. However, Tacoma generally maintains a relatively risk-adverse position in that the organization plans to critical hydro. Tacoma is planning to conduct future analyses on the interaction between these variables.
NWPPC	In the 1995 power plan, risk was assessed through expected total cost, observation of the distribution of outcomes and scenario analysis. With the introduction of economic risk assessment, we are frankly in unmapped territory. One of the more difficult questions is defining the risk threshold, i.e. outcomes for which costs are unacceptably high. One approach is to present specific situations to decision-makers (our advisory committees and Council Members) and then attempt to discover their level of comfort with economic risk. The risk associated with riskiest situation with which they feel comfortable could serve the as risk threshold.

IRP Practitioners' Responses -- 11	
What sources of risk are addressed in the IRP? **· Hydro variability? · Load scenario uncertainty and variability? · Fuel price scenario uncertainty and variability? · Resource and contract availability? · Transmission availability and congestion uncertainty? · Electricity market price scenario uncertainty and variability? · Emissions control scenario uncertainty (e.g. carbon tax)? · Other? · Relationships among these?**	
Avista	•Hydro variability? Yes. •Load scenario uncertainty and variability? Yes, for entire WECC • Fuel price scenario uncertainty and variability? Yes • Resource and contract availability? No contracts available, Forced Outages on resources. • Transmission availability and congestion uncertainty? Not addressed.• Electricity market price scenario uncertainty and variability? This is an output of the AURORA model, so yes • Emissions control scenario uncertainty (e.g. carbon tax)? Through scenarios Other? • Relationships among these? Correlations between hydro and gas prices
BC Hydro	
BPA	The within-year planning group performs risk analyses around most of the parameters indicated below; however, BPA's power rate case is most closely aligned with a utility's IRP. So the answers below are in reference to the analyses supporting BPA's current power rate case: •Hydro variability? Although the Augmentation Strategy in the current power rate case is based on adverse hydro; it assumes revenues based on average hydro. So BPA addresses hydro variability risks more or less conservatively depending on the application. The goal of BPA's "A Guide to Tools and Principles for a Dry Year Strategy" is to develop an infrastructure of tools that can be implemented in short-order to address drought and other resource-constrained situations. •Load scenario uncertainty and variability? BPA plans for medium loads in the long-term. BPA does perform within-year cold snap scenarios to determine if extraordinary measures are needed to balance load and resources.• Fuel price scenario uncertainty and variability? The current power rate case uses the best available information at the time of the rate case to estimate electricity market prices based on the most likely fuel price scenario. CRACs are used for rate adjustments when any of the assumptions, or combination of assumptions, are not born out in the realities of the market place. • Resource and contract availability? Again the most likely scenario is used to estimate augmentation costs with CRACs allowing for rate adjustments if the estimates are significantly different from reality. •Transmission availability and congestion uncertainty? Despite steps to minimize transmission constraints, transmission infrastructure concerns remain and will probably need to be incorporated in future analyses. • Electricity market price scenario uncertainty and variability? The most likely electricity market prices are used in the rate case.• Emissions control scenario uncertainty (e.g. carbon tax)? BPA does not explicitly address this variable.
Eugene	We have considered all of these in either quantitative analysis or in qualitative policy discussion. In most cases they translate into modifications to market price forecasts or resource costs. We have also used scenario formulation ("story telling") to think our way through combinations of future uncertainties – constructing plausible chains of decisions and actions through time that respond to future events. This is sometimes just a test to see if there are rational strategies that can address these unfolding events. We have commonly used influence diagrams to chart the relationships among many of these uncertainties. In some cases they result in correlation matricies, in most they simply inform our judgements about subjective probabilities. About the only other uncertainties we have examined relate to economic or financing issues like changes to public financing law and bond interest rates.
Idaho Power	Hydro variability? Three scenarios were analyzed: expected, 70th percentile, 90th percentile. A hydro condition at the 70th percentile would occur in 7 out of 10 years. •Load scenario

	uncertainty and variability? Three scenarios were analyzed: expected, 70th percentile, 90th percentile. Loads at the 70th percentile will occur in 7 out of 10 years. • Fuel price scenario uncertainty and variability? Expected case only. Future IRP's will consider fuel price uncertainty and variability. •Resource and contract availability? No. •Transmission availability and congestion uncertainty? Transmission availability was addressed. Congestion uncertainty was not included in the analysis. •Electricity market price scenario uncertainty and variability? Price variability was assumed to double from expected and/or decline 35% from expected. •Emissions control scenario uncertainty (e.g. carbon tax)? No.
PacifiCorp	The PacifiCorp IRP used average water in its deterministic analysis. However, stochastic runs varied hydro availability according to a two-factor, log-normal, mean reverting process. •Loads, fuel prices and electricity market prices were also treated stochastically with the variables varying according to a two-factor, log-normal, mean reverting process. Convergent Monte Carlo analysis was used in the stochastic analysis to vary resource availability (forced outages). •PacifiCorp produced the IRP using a transport model of its firm transmission rights. The model featured a 20-bubble topology for the deterministic analysis and a 7-bubble topology for the stochastic analysis. PacifiCorp's study did not address the intermittence of transmission outages or the availability and cost of non-firm transmission.• Cost associated with CO_2, NO_x, and SO_x emissions were modeled in the base case deterministic analysis. These costs were based on PacifiCorp's best estimate of new emissions requirements that are expected to emerge over the next several years. All three pollutants emission restrictions were assessed using a $/ton charge for emissions above their cap or paying credit below the cap. These costs/credits were then added to the overall PVRR of each portfolio.•In addition to modeling an $8/ton CO_2 base case, PacifiCorp also performed additional stress cases with $2, $25, and $40/ton scenarios representing various policy outcomes with varying implementation dates and cap levels. • There were other 'scenario risks', or risks that cannot be reasonably represented by a known statistical process, that PacifiCorp captured in the IRP. These 'scenario risks' were modeled as stresses. PacifiCorp performed a number of stresses involving wind modeling assumptions. Some examples of these stresses include, removing wind plants from the top performing portfolios, modifying wind resource cost assumptions related to production tax credits, green tags, transmission and integration, and attributing wind capacity to planning margin. • The risk analysis in PacifiCorp's IRP was used to illustrate contributors to risk in each portfolio. For example, risk analysis helped PacifiCorp distinguish the gas price sensitivity of each portfolio. Risk analysis also helped PacifiCorp illustrate the best and worst possible outcomes of a portfolio under different futures. PacifiCorp used the deterministic analysis to rank and screen portfolios to determine the least-cost plan.
PGE	
PNGC	We would consider most of these factors in a new IRP. Our current operational modeling considers most of these factors.
PSE	Hydro variability? Yes (Monte Carlo simulation). • Load scenario uncertainty and variability? Yes (scenario analysis). • Fuel price scenario uncertainty and variability? Yes (Monte Carlo simulation). • Resource and contract availability? Yes (extensive review and qualitative evaluation of wholesale energy market constraints and risks). • Transmission availability and congestion uncertainty? Yes (qualitative evaluation). • Electricity market price scenario uncertainty and variability? Yes (Monte Carlo simulation). • Emissions control scenario uncertainty (e.g. carbon tax)? Yes (scenario analysis). • Other? Wind production tax credits (scenario modeling). • Relationships among these? Correlations between gas and power prices, between hydro generation and power prices, and between hydro generation and gas prices.
Seattle	
Sierra Pacific	

SnoPUD	
Tacoma	•Hydro variability? Yes • Load scenario uncertainty and variability? Yes • Fuel price scenario uncertainty and variability? Yes • Resource and contract availability? Yes •Transmission availability and congestion uncertainty? No • Electricity market price scenario uncertainty and variability? Yes •Emissions control scenario uncertainty (e.g. carbon tax)? No •Other? Variables that could not be addressed quantitatively are addressed qualitatively through Scenario Analyses. • Relationships among these? See response to Question 10.
NWPPC	The 1995 power plan addressed hydro variability, load scenario uncertainty and variability, fuel price scenario uncertainty and variability, and resource forced outage rates and availability through Monte Carlo simulation. Emission tax and PNW purchase and sales uncertainty were modeled with scenario analysis. The fifth power plan will address all of these. We will retain the ability to assess the risk mitigation value of resource flexibility. We will provide a more complete assessment of system reliability with the *GENESYS* model. *Olivia* provides complete control over variables and correlations among variables and permits correlations to change over time.

IRP Practitioners' Responses -- 12	
What analytical tools or models do you use?	
Avista	EPIS AURORA model, WhatsBest linear programming module, in-house spreadsheets
BC Hydro	
BPA	Hydro-regulation tools are used to forecast the hydro resources. Power price forecasting tools are employed to forecast augmentation purchase prices as well as prices for which surplus power can be sold. BPA forecasts its customers loads in a variety of ways. Financial tools are used to estimate TPP and other financial indicators
Eugene	We have used commercial software (*Strategy Manager* from EPS Solutions, no longer supported) and staff designed and developed spreadsheets and workbooks. In the case of the spreadsheets and workbooks we have also incorporated the use of decision analysis software like @Risk and DPL. We are currently looking around.
Idaho Power	Aurora in some instances
Northwestern	
PacifiCorp	PacifiCorp uses Henwood's ProSym model for deterministic analysis and the MarketSym model for stochastic analysis.
PGE	
PNGC	
PSE	For its April 30, 2003 Least Cost Plan, PSE used AURORA to develop its base and alternate case long-term power price forecast scenarios. AURORA was also used to develop the 20 year load-resource outlook, essentially a monthly energy position report, for PSE's portfolio. PSE used a PC-based (Excel with Crystal Ball) model to evaluate resource adequacy levels and candidate resource portfolios.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	Aurora, internal hourly dispatch optimization model, internal price duration curve based model.
NWPPC	EPIS Aurora© is used to establish expected, long-term equilibrium power prices and is used to study west-wide system issues, like PNW purchases and sales. *Genesys* will inform us about a plan's impact on system reliability, given flexibility in the hydro generation system. *Olivia* is our primary risk model. It will help us identify a plan that minimizes costs, given our risk and reliability constraints. Olivia is not a systems model like Aurora and will use Aurora for long-term expected values of certain variables, such as power market prices.

IRP Practitioners' Responses -- 13	
What are the most important issues or problems for you in doing an IRP?	
Avista	A number of concerns come to mind. One is exactly what this effort is intended to address – regional (WECC) planning margins and their impact on the future marketplaces. Another concern is forecasting relationships between such variables as hydro runoff, natural gas prices, load, etc. Finally, large risks such as the effect of SMD make our planning more difficult
BC Hydro	
BPA	As pointed out by the Lessons Learned report, BPA needs to have certainty with regard to its future load serving obligations in order to prudently plan for FCRPS operations and any augmentation strategies. This is one of the key objectives of the Regional Dialogue. The establishment of a regional resource adequacy standard along with clarity as to each LSE's responsibility to meeting the standard would greatly help BPA understand its load obligations and develop resource plans to address these obligations.
Eugene	•Do we have the questions right? Are they the fundamental questions? •Can we credibly represent the important factors analytically or in a policy framework? •For the decision makers and our citizenry, is the process clear, open and understood? •How do we best communicate the complexity of the regional electric system, markets, development issues, and future uncertainties?•How do we articulate our "confidence" in the results of our analyses and deliberations?
Idaho Power	Some of the most important issues facing Idaho Power are transmission constraints, peak deficiencies and implementation of demand side management. Also, compliance with FERC standards of conduct has prompted some reorganization of our transmission and merchant groups which will affect the formulation of our IRP.
Northwestern	
PacifiCorp	There are definite risks to implementing the least-cost plan that cannot be quantified in the IRP. We call these risks 'Paradigm Risks' because they can not be reasonably represented by a number. The assessment of these risks is usually qualitative rather than quantitative. Examples of these risks for PacifiCorp include, cost-recovery, the impact of structural changes in the industry (RTO and SMD), state deregulation and restructuring (who do we plan for?), hydro-relicensing, and comprehensive air initiative. These implementation risks require the IRP to remain flexible to respond to these uncertainties.
PGE	
PNGC	The most critical factor for us is defining what power will be available from BPA and at what cost over a long term.
PSE	One of the challenges for doing integrated resource planning is the current upheaval in the energy industry as a whole. While the momentum toward retail deregulation has stalled, the outlook for the overall structure and functions of the industry is not clear. For example, it is difficult to predict whether or when the merchant generation sector will recover and what role it will play in the industry over the long term. There is also a lack of "visibility" regarding resolution of the credit issues that currently make it very difficult for wholesale market participants to do business with each other. As a result, while a well-functioning wholesale energy marketplace (for both gas and power) is desirable, the current problems and lack of clarity regarding ultimate outcomes make it difficult for utilities to plan resources to meet their obligation to serve.
Seattle	
Sierra Pacific	
SnoPUD	
Tacoma	•Knowing whether a fundamental shift in a key-planning variable is permanent or short-term (e.g., natural gas prices). • Adequately addressing uncertainty. •Limited staff resources.

	• Ultimately, finding the appropriate balance between investment in firm supply resources and reliance on the wholesale power market.
NWPPC	There are numerous technical issues with which we are wrestling. The basic question is how to make clear for decision-makers the choices with respect to how much of an "insurance premium" makes sense. The broader question from the Council's standpoint is how to fulfill the requirements of the Power Act for a *regional* plan and provide information and tools that are useful for individual decision-makers.

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