An Introduction to Integrated Resources Planning

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About International Rivers

International Rivers is a non-governmental organization that protects rivers and defends the rights of communities that depend on them. International Rivers opposes destructive dams and the development model they advance, and encourages better ways of meeting people's needs for water and energy and protection from destructive floods.

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Cover Photo courtesy of Wikipedia. The Brazos Wind Farm, also known as the Green Mountain Energy Wind Farm, near Fluvanna, Texas.

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Abbreviations

CPA	Conservation Potential Assessment
CRT	Cathode Ray Tube
DSM	Demand-side Management
EE	Energy Efficiency
GDP	Gross Domestic Product
GW	Gigawatt
IAEA	International Atomic Energy Agency
IRP	Integrated Resources Planning
kWh	Kilowatt-hour
LEAP	Long-range Energy Alternatives Planning System
LED	Light-emitting Diode
LOLP	Loss of Load Probability
MW	Megawatt
MWh	Megawatt-hour
NPCC	Northwest Power and Conservation Council
OECD	Organization for Economic Cooperation and Development
PDP	Power Development Plan
PGE	Portland General Electric
PSE	Puget Sound Energy
WASP	Wien Automatic System Planning

Introduction

Altering the course of power sector development towards less environmental and social impact by opposing specific power plants can be exceedingly difficult. By the time a power plant is at the stage where it is seeking financing for construction, government bureaucracies, developers, banks, and powerful individuals have all invested considerable time, money, and personal identification with the project. Even if local affected populations, civil society, and activists manage – through great effort and perhaps a certain amount of luck – to stop a particular project, far too often the victory is short-lived; the project pops up again hydra-like with renewed vigor in a new changed location – often as a scourge to a different affected population less able to organize coordinated and strategic resistance. In the course of a campaign, it is not uncommon, as well, to be challenged by officials and utility executives with the refrain, "You don't want hydropower. What do you want instead? Coal? Nuclear? You have to choose one or the other!"

These situations (the difficulty of stopping projects once they reach the planning stage; and the inevitable "what power plant do you want us to build instead?" conversation) suggest that it can be very useful to move upstream in the power sector planning process – to focus attention on the stage at which Power Development Plans (PDPs)[1] are being made. A PDP specifies what types of power plants will be built in each year. At the PDP stage the commitments for particular power system development trajectories can be malleable, and for policy activists there are several key characteristics that can be used to shape outcomes:

- Assumptions are uncertain, and even small changes in assumptions yield large changes in the plan 15 or 20 years out;
- Utility planners generally already claim to follow ideas of 'least cost' but – as we shall see below – frame the question of "least cost to whom" too narrowly;
- Conventional "business as usual" electricity planning practices and processes often lead to suboptimal results (excessive costs and risk). These failures can be pointed to as evidence that change is needed.

In reality it is likely that a strong case can be made – *in any country* – that the best (lowest societal cost, lowest risk, lowest environmental and social impact) alternative to a particular new mega-scale power plant project is better planning and comprehensive energy efficiency / demand side management (EE/DSM).[2] This guide will help you to make this case.[3]

This paper looks at a time-tested alternative to the conventional power sector planning paradigm. **Integrated Resource Planning (IRP)** is a planning approach that has the potential to take a society-wide perspective, incorporate public participation in meaningful ways, and has a strong track record in creating plans that are low-cost, low risk, and with outcomes that minimize environmental and social impacts. IRP has close associations with energy efficiency: investing in helping customers to save electricity is typically considerably less expensive than building new power plants and fueling them for decades, and though the IRP process in itself is agnostic about whether demand-side options should be chosen over supply-side options, it is insistent that demand- and supply-side options for providing energy services to consumers must both be considered, and evaluated in an even-handed way. Utilities that rigorously implement IRP consistently report good news: there are many opportunities for energy efficiency investments, and IRP can lead to substantially lower customer bills while avoiding the social and environmental disruptions and destruction that accompany new power plant construction and operation.

Be forewarned: while IRP can be a very effective way of addressing evolving needs for electricity services, it is also based on principles and ideas that can challenge conventional culture in electric utilities and regulatory agencies. Yet, these ideas speak for the need for reforms that align incentive structures and regulatory arrangements in ways that are consistent with the public interest to overcome the fundamental issue that electric utilities earn revenue selling electricity while energy efficiency measures threaten to lower utility revenues.

To better understand IRP, let's start with a critical description of the conventional power sector planning process.

What Are 'Conventional Power Sector Planning Practices'?

Conventional power sector planning practices generally comprise a bundle of practices and assumptions that are generally referred to (especially by utilities) as "least cost planning." What they generally mean, when pressed, is "least cost generation planning from the utility's financial perspective." With regional differences and measures to take into account country-specific laws, this 'least-cost' planning typically arrives at a power development plan through a process that comprises load forecasting, developing assumptions about investment and operations costs of a limited list of options, and a computerized optimization that chooses among the limited options considered. These practices are discussed below as we have observed them, especially as practiced in some (but not all) developing countries.

We should point out that in some countries power sector investment decisions do not follow a least cost planning framework as discussed below. For example some countries with large hydropower ambitions and power thirsty neighbors build projects primarily for electricity export – with investment decisions having little to do with load forecasts and more to do with planning and sequencing of exploiting hydropower sites. While many elements of IRP can be useful even in these situations (for example, using indicators to determine the extent to which stated goals are met by plans), this paper focuses more on the use of IRP as an alternative to conventional "least cost" PDPs.

LOAD FORECASTING IN A CONVENTIONAL PDP

The foundation for the conventional PDP is an official forecast of future electricity consumption. Because electricity cannot be cost-effectively stored at national-scales, supply must be balanced with demand at every moment. Thus, the forecasted peak demand figure is important because the peak demand plus a reserve margin determines the amount of installed generation capacity that is necessary to ensure adequate power supply in the country. Because power plants and other related investments have long lead-times (typical large thermal plant requires two to three years of construction time, a typical hydropower plant requires at least four, and nuclear power plants at least five not including licensing and approval), planning ahead is necessary to avoid power shortages. Inaccurate forecasts, however, could also lead to either a shortage situation (too few power plants built) or surplus situation (too many power plants built). Each has significant economic ramifications.

Load forecasts are typically created every several years, and make projections for the next 10 to 30 years. Load forecast methodologies employed in conventional power sector planning typically have two characteristics:

1. They are developed by a committee (generally comprised of Ministry officials, utility representatives, and consultants) that meets behind closed doors.[4]

2. The methodology used to forecast demand is primarily based on medium and long-term GDP growth forecasts. In many cases, long-term demand projections are based on economic growth predictions multiplied by "electricity elasticity," the ratio of the electricity demand growth to GDP growth. As an economy grows and the majority of population centers are already electrified, the "multiplier" should decline. However, demand projections in Thailand in late 1990s, for example, were based on an assumed constant multiplier of about 1.4; that is, electricity consumption is "expected" to grow 1.4 times as fast as economic growth.

While there is an obvious appeal for the simplicity of this "economic growth times electricity elasticity" approach, demand forecasting approaches that rely heavily on econometric forecasts have often led to demand projections which far outstripped the real electrical demand. In the Pacific Northwest of the U.S., such over-predictions of demand led to plans to build 20 nuclear and coal units, of which ultimately five coal plants and nine nuclear plants were scrapped. This debacle cost consumers $7 billion (Weston 2009a) and created the largest municipal bond default ($2.25 billion) in US history (Alexander 1983). In Thailand, similar inflated load forecasts were blamed for 400 billion baht ($13 billion) accumulated overinvestment in the power sector (The Nation 2003).

One reason for these failures is that as demographics, industries, and technologies change, so does the energy intensity of the various energy services employed. As technology has progressed, commercial industrial equipment and residential appliances have become more efficient (think of compact fluorescent light bulbs vs. incandescent light bulbs, flat screen computer monitors and TVs versus the old-fashioned bulky cathode ray tube (CRT) TVs and monitors). These changes may have not been captured well in load forecasts. Another reason for demand forecast inflation is that the producers or economic growth projections are generally under political pressure to "aim high" as few politicians want their administration to be a time of low expected economic growth. Moreover, forecasters generally assume that a "normal" state of affairs is uninterrupted economic growth, whereas reality is bumpy for various reasons not accounted for in projections: economic bubbles burst, 100-year floods occur, or the global economy slumps. These high economic forecasts have real consequences as they are translated directly into high electricity demand projections.

In practice, conventional load forecasters may introduce a few scenarios: "base case" as well as "low" and "high" with the base case forecast selected as basis for the PDP.

With the demand forecast in hand, the next step in conventional planning is to determine the generation requirement, with the key assumption being to maintain a minimum reserve margin.

CALCULATING GENERATION REQUIREMENT

In developing countries, the generation requirement is commonly determined primarily in peak capacity in megawatts (MW) while total energy output in Megawatt-hours (MWh) is a secondary consideration. To ensure system reliability, generation requirement is often determined by maintaining a minimum reserve margin beyond the projected peak demand, to allow for unanticipated demand for power, equipment failure, or other unforeseen events. A proper amount of reserve margin (normally 10% to 30%) is a balance between achieving high reliability standards (by building and maintaining large surplus capacity to withstand power disruptions from unexpected events) and cost. As a power system grows, the reserve margin percentage tends to decline because of diversified risks of any one large plant affecting the entire grid.

Though a technical concept,[5] reserve margin can hide subjective judgments by utility planners. A small increase in reserve margin can lead to many more power plants being "required."

OPTIONS CONSIDERED IN A CONVENTIONAL PDP

Once the generation requirement is determined, planners decide what generation options will be considered to meet the required demand, and make cost assumptions for fixed costs (construction) and variable costs (fuel, operations) of these different options as well as key variables such as the assumed discount rate.

The options considered in conventional planning are often limited to large-scale supply options only (100s of MW per plant) thermal (gas, coal, oil), nuclear, and hydropower.[6] The restriction of options to these large generation plants is sometimes driven by limitations of modeling software that many utilities use (such as Wien Automatic System Planning[7] – WASP), or because of limited data collecting and analytical capabilities/habits of utilities or their consultants even if using more modern software (such as Ventyx Strategist[8] or Ventyx System Optimizer[9]) that can accommodate data on distributed generation and demand side measures. Clearly, modeling a few large power plants in a computer optimization is easier than modeling hundreds or even thousands of smaller power plants or energy efficiency measures.

In many cases, this is less a matter of lack of ability and more a consequence of the mindset of planners. In addition to limitations of software, data or corruption, some planners simply do not consider energy efficiency or demand-side management as planning (or investment) options. They have an outdated view of considering only supply options even though the former have proven elsewhere to be the most economic investments to meet growing demand. Though these planners may understand the merits of energy efficiency, they still have a conceptual bias against viewing demand side measures as a potential resource that can be planned for and invested in, or they lack confidence that savings can be verified.

Other factors that sometimes limit power plant choices in a country are less savory. Sometimes it is a matter of corruption: the small group with decision-making authority makes choices that are influenced by personal interests in particular projects. Sometimes it is a matter of pork-barrel politics in which power planning is influenced by the politics of allocating large infrastructure projects to key constituencies.

FUEL PRICE ASSUMPTIONS IN A CONVENTIONAL PDP

Despite the well-known volatility of fossil fuel prices (especially natural gas[10]), PDPs generally take a 'snapshot' price as an input into conventional modeling, or make simple assumptions about fuel price escalation. Sometimes sensitivity analyses are run considering high and low fuel prices. While a single assumed price for each fuel is a much easier variable to accommodate in computer models, this practice tends to dismiss the considerable impact of volatile prices on the costs associated with particular power supply options.

DISCOUNT RATE IN A CONVENTIONAL PDP

Another key factor is the discount rate. While the discount rate sounds technical and innocuous, it has significant implications. The discount rate is the amount by which future cash flows (revenues, expenses) are valued lower than current cash flows. A high discount rate generally favors fossil fueled generation that has relatively low capital costs, but high or uncertain fuel and operating and maintenance costs.

Conversely, low discount rates favor investments like energy efficiency measures or renewable energy that have low ongoing costs but may have high capital costs (especially in the case of renewable energy).

OPTIMIZATION AND SELECTION OF PROJECTS IN A CONVENTIONAL PDP

Forecast demand, together with fixed and variable costs, efficiencies, construction times, discount rate, and other data, are keyed into software which simulates the existing power supply system with new candidate additions and chooses a portfolio of power plants that have the lowest generation cost. To be more precise, it finds the package of candidate plants that minimize the discounted cash flow (capital and operating expense) over the time period in the demand forecast. In many cases, a PDP may not simply adopt the results of a least-cost model, but may also incorporate other criteria, such as energy security (through increasing diversity of fuels and their sources), or regional balance within the country.

The utility then builds this generation and its associated transmission lines, and passes costs on to consumers.

CRITIQUE OF THE CONVENTIONAL PDP

This type of modeling has glaring omissions. It typically includes only generation costs (and not social and environmental costs or even transmission cost). Transmission costs can account for 40% or more of total system expansion costs. By simply adding transmission costs "after the fact" once generation costs are minimized, the optimization in conventional planning misses benefits that accrue from decentralized energy efficiency measures or generation which require no or substantially less investment in transmission. True least cost planning should instead be based on the economic costs (including environmental externalities) of delivered electricity services to end users.

Conventional planning also treats risk in a very limited way: it makes a fixed assumption about all costs (including, crucially, fuel costs) and then optimizes based on this assumption. This yields a plan that is only optimized for a future that turns out to be similar to the assumptions that were adopted. The conventional planning process provides little or no information about the sensitivity of the selected plan to variations in key assumptions, and even less information on the sensitivity to changes in multiple variables simultaneously (for example, high natural gas price + drought year + carbon pricing). In this way, best practices IRPs transparently illuminate the implications of assumptions about the future, in contrast to conventional power planning processes that can bury key subjective assumptions in technical jargon or worse, as hidden inputs into models to which the public does not have access. Table 1 indicates factors often missing from least-cost generation expansion planning that are typically included in an IRP.

Table 1: Factors considered in conventional "least cost generation expansion" planning vs. IRP

	Conventional "Least-cost" generation expansion planning	IRP
Bottom-up load forecasting	No	Yes
Generation costs	Yes	Yes
Demand-side management options and costs	No	Yes
Transmission and distribution costs	No (typically added after optimization)	Yes
Risks of fuel price volatility, drought, carbon taxes, etc.	Little or no consideration	Yes
Social and environmental "externality" costs	No	Yes
Public involvement throughout process	No	Yes
Scenario and sensitivity analysis to ensure "least-cost" under different cost or demand assumptions	Little or no consideration	Yes

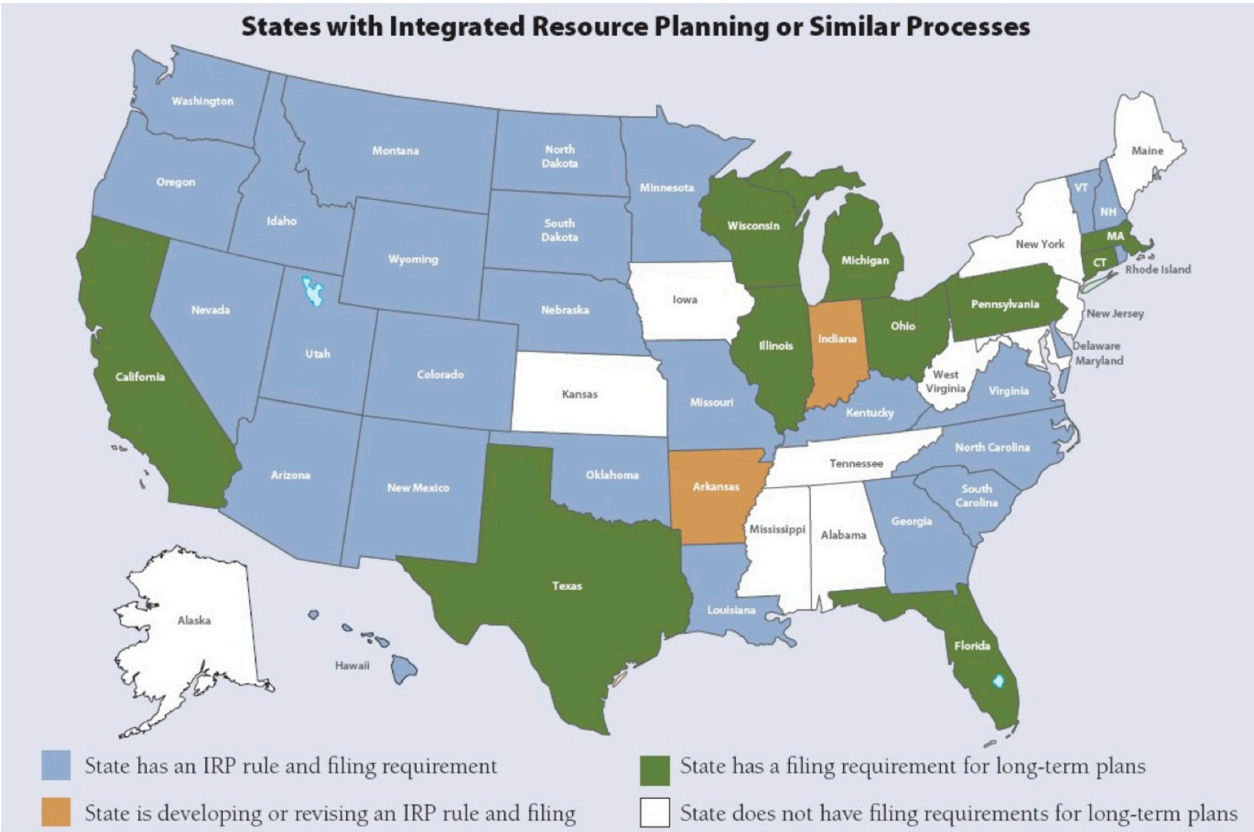
What is Integrated Resources Planning?

IRP was borne out of financial crises in the 1970s and 1980s in the US that arose from utilities investing in expensive power plants that were not needed, and from cost overruns from nuclear power plants. These included the crisis in the Pacific Northwest discussed above, and a similar crisis in the US eastern seaboard. One of the worst cases was the 820 MW Shoreham nuclear power plant, which in 1968 was projected by Long Island Lighting Co. in New York to cost $350 million. When it was finally completed 20 years later, its final cost was 15 times the original estimate. The plant never went into commercial operation and was sold to the state for $1 in 1989. Other plants in the area saw final costs ten-fold higher than original estimates. These cost overruns and inflated load forecasts led to bankruptcies of a number of utilities including Public Service of New Hampshire, Eastern Utilities, New Hampshire Electric Coop, Eastern Maine Electric Coop, and Vermont Electric Coop. (Weston 2009a)

Responding to the public outrage that ensued, regulators, energy policy makers, and citizen advocates developed Integrated Resource Planning. The more sophisticated planning process considers a full range of power sector investments to meet new demand for electricity, not only in new generation sources, but also in transmission, distribution, and – importantly – demand-side measures such as energy efficiency on an equal basis. These IRP plans typically use a twenty- to thirty-year planning horizon on complex computer models that include risk assessment. In many

An electricity pylon. Photo courtesy of Google Images.

Figure 1: States with Integrated Resource Planning or similar processes. Source: Wilson and Biewald 2013



jurisdictions, IRP integrates environmental and other external costs and benefits, and generally includes regulatory mechanisms to overcome utility and customer barriers to demand-side efficiency.

The US state of Vermont's legal definition of IRP is typical of many jurisdictions:

> "A 'least cost integrated plan' for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs."
>
> Title 30, Vermont Statutes Annotated, §218c (a)(1)

IRP was embraced by a number of utilities in the East, Mid-west and West Coast of the USA in the 1980s, where it demonstrated that energy efficiency is the most cost-effective resource available. However, IRP lost ground in the neo-liberal post-Reagan-Thatcher era of the 1990s as policy makers, politicians and regulators embraced the idea that deregulation and competition were likely to reduce costs and allocate risks better than regulation. Deregulation in the power sector failed to live up to its promise and with the Enron meltdown, the California electricity crisis, and other events it became clear in the 2000s that unregulated competition in the power sector failed to protect consumers. As of 2013, interest in IRP is growing again, and it is now required by law or by administrative code in 28 states (Establishing scope and objectives).

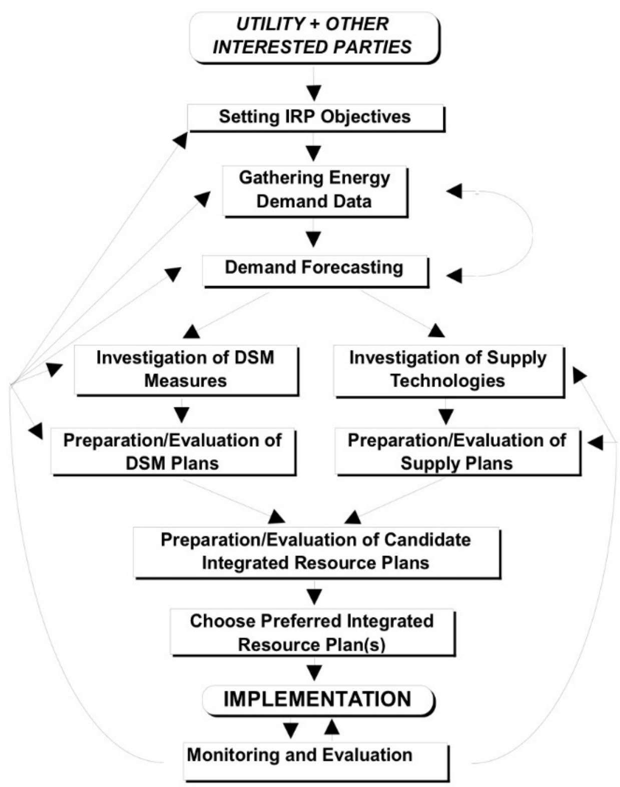
It is notable that the Vermont Statute uses the term "energy services" rather than, say, "electricity" or "gas". A mantra of energy efficiency advocacy organizations has been to shift the focus of power planning (and utilities) from providing power to providing, for example, the cooling services normally provided by the electricity supplied to the air conditioner. It is this attempt to get the utility out of the business of just selling kWh that seeks to match incentives more closely with the interests of society at large.

What are the Steps in an IRP Process?

An IRP process is not a silver bullet, but it does address many of the shortcomings of conventional power planning. The IRP process consists, generally, of the following steps:

- Establish scope and objectives;
- Survey energy use patterns and develop demand forecasts;
- Investigate electricity supply options;
- Investigate demand-side management measures;
- Prepare and evaluate supply plans;
- Prepare and evaluate demand-side management plans;
- Integrate supply- and demand-side plans into candidate integrated resource plans;
- Select the preferred plan; and
- During implementation of the plan, monitor, evaluate, and iterate.

Figure 2: The Integrated Resource Planning process. Source: von Hippel and Nichols 2000



PUBLIC INVOLVEMENT

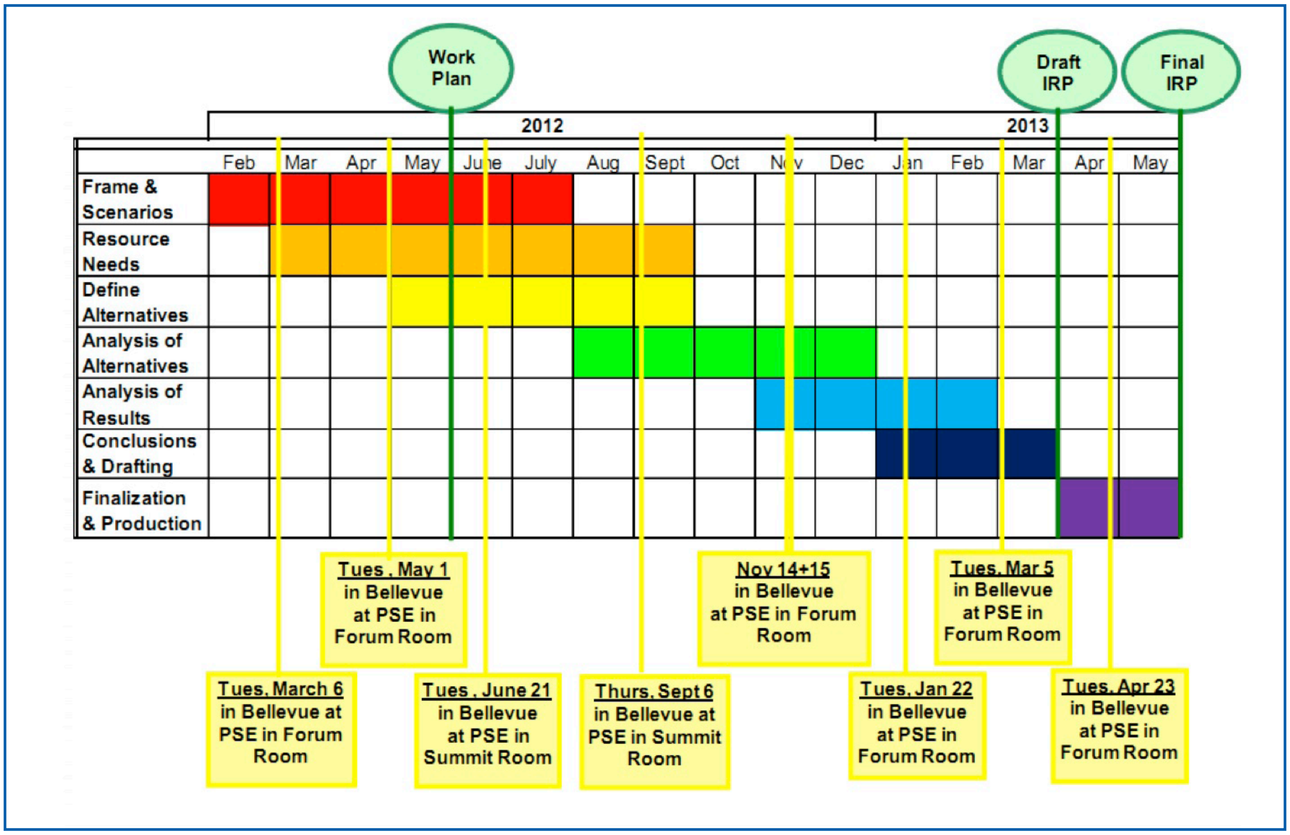
Because many groups in society are affected by the development and operation of the power system, a wide range of stakeholders have legitimate basis for being part of the planning process. A best practice IRP process includes not only utility representatives, but also representatives of energy consuming sectors, community groups, advocacy groups, and government ministries (economic planning, environmental protection, and energy, etc). Incorporating the views of a broad spectrum of those affected by planning decisions fosters consensus and helps avoid polarization as plans are implemented.

These views should be solicited and incorporated at multiple occasions in the development of the IRP. These objectives may conflict with one another to varying degrees. Therefore, preparing, deciding upon, and implementing a preferred resource plan requires both a series of objective analyses (based on solid facts, that explores consequences of different choices) and the use of processes (incorporating principles of transparency, accountability, and public participation) by which the values and judgments of stakeholders are applied in developing plans. below shows the work plan schedule for the 2013 IRP being conducted by Puget Sound Energy (PSE) in Washington State with times and locations for seven public meetings which are dispersed throughout PSE's 16-month IRP process.

ESTABLISHING SCOPE AND OBJECTIVES

Part of the scoping process requires consideration of geographic scale. Literally, "how big is the IRP?" IRPs often make sense at a national scale (particularly if the electrical system in question coincides well with the area within national boundaries). However, in some cases power system planning may well need to transcend national boundaries. For example, an IRP that addressed the power system in Laos might include Thailand and Vietnam within its scope since most electricity generated in Laos (currently and in future plans) crosses borders for use in these countries. While politics and sovereignty may limit opportunities for transnational planning, it is reasonable to ask whether Thailand's electricity needs can be more cost-effectively served by measures other than Lao hydropower and coal imports. At the very least a regional IRP can serve as a benchmark against which to measure options

Figure 3: Stakeholder process in Puget Sound Energy's IRP. Source: (Puget Sound Energy 2013)



chosen within the countries separately.

IRP can be thought of as a process of planning to meet users' needs for electricity services in a way that satisfies multiple objectives for resource use. As such, it does not presume that the only objective to be optimized is cheap electricity that meets reliability standards. Broad objectives can include:

- Conform with national, regional, and local development objectives.
- Ensure that all households and businesses have access to electricity services.
- Maintain reliability of supply.
- Minimize the short term or long term economic cost of delivering electricity services or their equivalent.
- Minimize the environmental impacts of electricity supply and use.
- Enhance energy security by minimizing the use of external resources.
- Provide local economic benefits.
- Minimize foreign exchange costs.

These objectives may conflict with one another to varying degrees. Therefore, preparing, deciding upon, and implementing a preferred resource plan requires both a series of *objective analyses* (based on solid facts, that explores consequences of different choices) and the use of *processes* (incorporating principles of transparency, accountability, and public participation) by which the values and judgments of stakeholders are applied in developing plans.

Once planning objectives have been agreed on, indicators are ascribed to each objective. Key indicators might include: cost per kWh and per peak MW, the percentage of the population served with electricity, amount of foreign currency spent on energy imports, or the tonnes of carbon dioxide released. Sometimes, social objectives may require qualitative descriptions rather than quantitative measurements.

SURVEY ENERGY USE PATTERNS AND DEVELOP DEMAND FORECASTS

Once objectives are determined, the next step is to understand current energy use patterns within the scope of the IRP and make projections about the future. As with conventional planning, a load forecast in an IRP process looks at energy and power requirements five to 30 years into the future. Solid data on energy usage patterns is the foundation to a strong IRP. Some of the types of information used in IRPs include:

- Energy end-use data: This data includes the number of households using specific electric appliances, the number of commercial, institutional, or industrial consumers using different types of electric equipment, and the amount of electricity used per customer per end use. Countries serious about effective power system planning should work to develop and maintain historical records for each customer class and major end use.[11]

- Electricity sales records: Sales records by geographical area and by customer class (for example, household, commercial and industrial classes) are needed, along with the number of customers by class and by area, for as many historical years as are available.
- Demand records: Data on power demand that charts the MW load requirements over days, weeks, months, and years are needed to determine the relationship between electricity sales and the amount of generation capacity required. Disaggregated data (broken down by customer class) are useful. The shape of the load curve (the variation of peak loads over time, or the "load profile") helps to determine what types of generating capacity are needed.
- Economic and demographic historical data and projections: Historical data on economic performance, and population or the number of households together with economic and demographic projections are useful for the portion of demand that is difficult to capture with end-use data.

With this data in hand, modelers build forecasting models for future electricity demand. For a comprehensive forecast, several modeling techniques may be used simultaneously if one approach has gaps in available data. Of the model types above, end-use models are generally the most accurate – but also the most data-intensive.

End-use approaches have several advantages. They can be quite detailed, providing more information for planners. They can provide integrated forecasts of both energy and peak power demands. The assumptions used in forecasting are usually easy to follow, check, and revise as new data become available. Importantly, end-use forecasts provide a data-rich framework for estimating the impacts of energy-efficiency options and demand-side management (see page 5) by making changes to parameters used in the baseline forecast.

On the other hand, end-use forecasts are data-intensive. Surveys of different types of buildings are usually needed to collect good data on energy end-uses. This data costs real money to collect.

In areas where end-use data is insufficient, *Econometric forecasting* can be used. Econometric forecasting looks for statistically significant historical relationships between economic variables and electricity sales or peak demand. Variables used to develop econometric relationships may include household income, electricity prices (by consumer group), prices for other household necessities, employment (by sector and

Selected End-Use Electric Energy Efficiency Measures

Residential Sector

- Higher-efficiency appliances (air conditioners, refrigerators, stoves, water heaters, electronic devices)
- Devices that save hot water (efficient washing machines, low flow shower heads and other plumbing fixtures)
- Compact fluorescent lamps or LEDs
- Automatic lighting controls (timers, or occupancy sensors)
- Building envelope improvements (insulation, window improvements) to reduce cooling, heating, and sometimes lighting needs.

Commercial/Institutional Sectors

- Higher-efficiency air conditioning, refrigeration equipment
- High-efficiency fluorescent bulbs, lamp ballasts, and lighting fixtures or LED lights
- Lighting, cooling, space heating, and water heating controls
- High-efficiency office equipment (monitors, computers)
- Building envelope improvements
- High-efficiency electric motors, drives, and controls

Industrial Sector

- Process improvements
- High-efficiency electric motors, drives, and controls
- Applicable commercial/institutional sector measures

Other Sectors

- High-efficiency cooling and refrigeration equipment for the agricultural sector
- High-efficiency electric motors, drives, and controls for mining and transport applications
- High-efficiency lighting products for street lighting

Source: adapted from Von Hippel and Nichols 2000.

sub-sector), labor productivity, tourism, industrial or agricultural output (measured in physical quantities or monetary terms), commercial-sector output (by sub-sector), use of other fuels, and the prices of other fuels.

Once statistically significant historical relationships between economic or demographic variables that affect electricity use or demand are identified and specified, projections for the relevant economic variables are used as inputs to the econometric model to forecast electricity use and/or peak demand. As the factors that influence household electricity use are generally different from those that affect commercial, institutional, or industrial electricity use, IRP econometric forecasts, at least of electric energy use (as opposed to peak demand), are typically done separately for each major customer group, then aggregated to estimate system-wide sales.

Since the future is inherently uncertain, most forecasters prepare a "base case" and several (or dozens) of alternative forecasts of electricity use and peak demand. Alternative scenarios give planners an idea of the sensitivity of forecast results to changes in the assumed value of key parameters.

In the IRP model these forecasts, and the assumptions embodied in them, are available to the public for comment and further input.

INVESTIGATE ELECTRICITY SUPPLY OPTIONS

The next step in an IRP is to investigate supply options. This includes consideration of all applicable options to supply needed electricity, together with the related infrastructure (transmission and distribution upgrades, environmental controls, fuel supply systems, and waste disposal processes). Supply options included in an IRP cover a full range of scales, from central power stations of tens to thousands of MW, decentralized options interconnected at distribution level voltages as well as a broad range of fuels including renewable energy sources. In an IRP, capital and operations costs of various supply options are collected, as well as the technical characteristics regarding scale and dispatchability.

The entire portfolio of generating sources must be matched to the varying electrical loads encountered hour-by-hour, week-by-week, season-by-season. In a national or regional grid, conventionally, these needs are met by considering capacity of three types: baseload, intermediate load, and peaking power plants. Baseload power plants typically have lower fuel costs and higher investment costs, and are designed to operate most hours of the year. Intermediate plants typically operate 15% to 50% of the time. Peaking power plants provide electricity when demand is highest, and may only operate a small percentage of the hours in a year.

As more intermittent renewable energy comes online new challenges arise to match supply with demand in real time. Tools available include expanded use of peaking power plants, enhanced flexibility in scheduling transmission, widespread deployment of dispatchable loads (loads that can be turned on and off by utilities if needed), and contracts that provide for the ability to curtail renewable generation at times.

Options for transmission and distribution appropriate for candidate generation technologies must be assessed and their cost estimated. If the IRP includes expanded rural electrification, then it may be necessary to map in detail the target areas and consider costs of grid extension compared to the cost of isolated mini-grids or household scale solar home systems.

Attributes of each supply option should be noted, including:

- Plant capacity (measured in MW)
- Maximum and optimal capacity factors (fraction of a year the plant is likely to generate electricity)
- Fuel type
- Efficiency (amount of electricity per unit of fuel)
- Fuel costs
- Reliability
- Capital and operating costs
- Lifetime
- Decommissioning costs
- Foreign exchange requirements (what fraction of cost is spent on imports?)
- Environmental impacts (air pollutants, solid wastes, cooling water, submerged areas and relocated households)

At the stage of analysis, an initial screening is generally conducted to eliminate options that are clearly uneconomic.

INVESTIGATE DEMAND-SIDE MANAGEMENT MEASURES

Demand-side management, or DSM, refers to programs or projects undertaken to manage the demand for electricity: reducing electric energy use, changing the timing of electricity use (and thereby the profile of peak power demand), or both. By reducing the demand for electric energy and power, demand-side management options reduce the need to generate electricity, and also reduce loads on transmission and distribution systems. In this stage of an IRP, demand side options are identified and their cost and performance is analyzed, and the most promising options are selected.

The list of potential DSM options for utility systems is longer than the list of supply options. DSM options can be roughly divided into four categories, as follows.

1. **<u>Information and/or Incentives to Encourage Efficiency in Electricity Use</u>**

   One class of options is to provide information to electricity consumers on how to use energy wisely and efficiently, and to provide pricing structures that help spur customers to change the amount and timing of energy use.

   The energy efficiency software company Opower provides one emerging example of information awareness that harnesses the power of social media. Customers of utilities that subscribe to Opower's software service receive monthly detailed comparisons of their electricity consumption with similar households in their neighborhoods together with tips on energy savings. Opower subscribers can also use Facebook to automatically compare their energy consumption with friends and peers. Opower claims reductions in electricity consumption of 2-3% by customers in utility areas that enroll in their programs.

Pricing structures can provide a powerful incentive to save. Block rate tariffs charge higher rates for those customers that consume greater amounts of electricity.

Although there is uncertainty in the estimates of electricity or peak power savings from all types of DSM measures, the savings from information/price incentive measures can be the hardest to quantify.

2. **Higher-Efficiency Technologies**

Energy-efficiency measures reduce energy consumption (and peak loads) by substituting more efficient appliances and equipment for less efficient units or systems. Energy efficiency measures are available for virtually every end-use application. A small sample of generic measures, organized by customer group, is presented in Table 2.

3. **Fuel-Switching Technologies**

In an IRP, the most common types of fuel-switching options are those that save electricity and reduce peak loads by substituting another fuel for electricity. Illustrative fuel choice alternatives include:

- Use of natural gas or solar energy (instead of electricity) to provide space heat, water heat, or industrial process heat.
- Use of natural gas or solar-thermal absorption chillers or natural gas engine-driven chillers (instead of electricity) for air conditioning or refrigeration.

4. **Load Management**

Load management measures reduce peak demand by shifting power use from times of high power demand (for example, during the day or early evening) to times of lower demand (during the night). Examples include:

- Water heater controllers for household applications. These can be simple timers that turn off appliances during peak times, or electronic controls ("load control") activated by the utility system operator. With centrally activated load control systems, different groups of end-use equipment can be cycled off for a few minutes during peak loads.
- Ice-storage or water chiller systems for cooling. Chilled water or ice is made at night by refrigeration, and stored until cooling is needed (for example, in an office building or hospital) during the day. The ice is then melted in a heat exchanger and used to cool the building.
- Special "interruptible" rates. Large volume electricity users may be offered price discounts in exchange for allowing the utility to disconnect all or a portion of their electrical equipment when the utility system is short of generating capacity.

Ultimately energy efficiency measures will be adopted based on the attractiveness of their attributes to the entity with authority in making the facility's investment decisions. Attributes of energy efficiency that should be noted include:

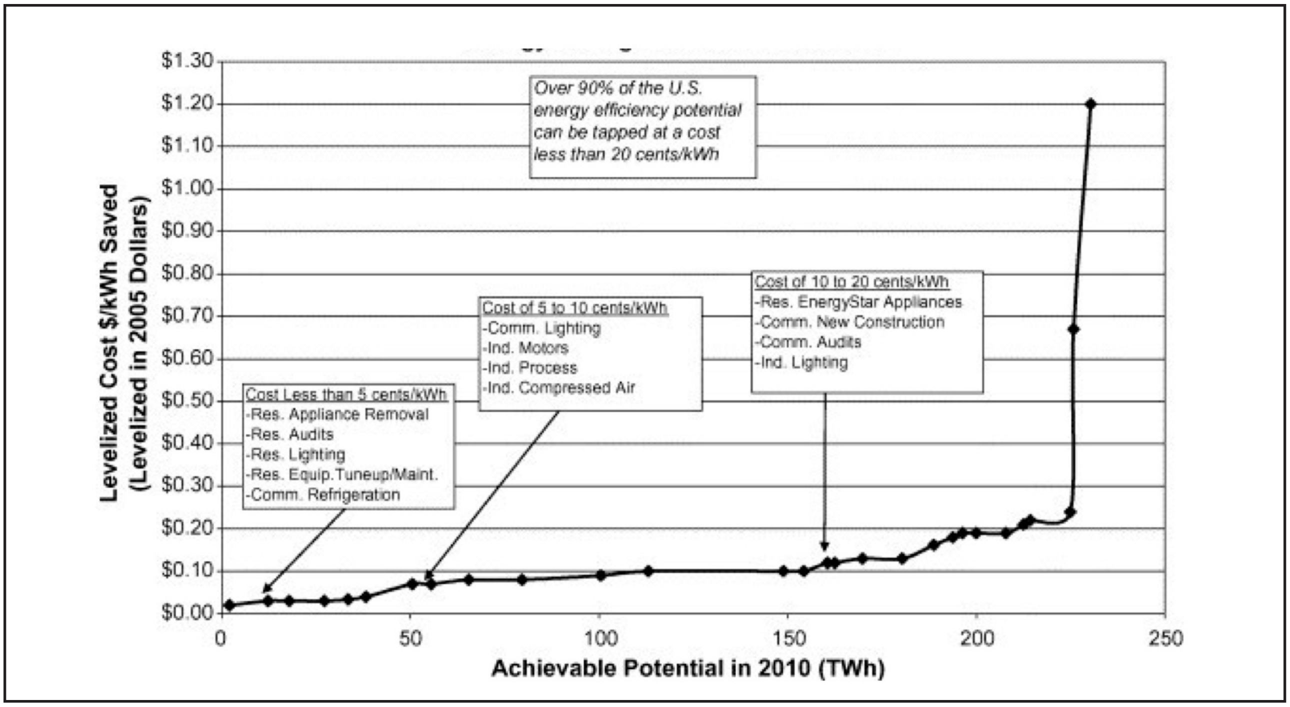
- Applicability (market size, and identification of sectors and end-uses)
- Fuel type
- Reliability and lifetime (based on experience in previous applications)
- Efficiency (energy and power saved relative to standard equipment)
- Capital and operating costs
- Environmental impacts
- Foreign exchange requirements and local input (fraction of the materials and technology that can be provided locally)

While there may be important variations country-by-country, a good starting point for this information, as well attributes of supply-side technology, is the "Technology & Environment Data Base" available at www.leap2000.org.

With these data collected, measures are screened to select those with lower costs of saved energy (measured in kWh over the lifetime of the measure). One common conceptual tool is a "cost of saved energy curve." The example in Figure 4: Cost of Saved Energy Curve Showing US Energy Efficiency Achievable Potential Energy Savings in 2010 – All Sectors. Source: (Gellings, Wikler, and Debyani 2006). shows how much electricity might be saved beginning with the lowest-cost measure, arranged in order of increasing cost. If the objective is to minimize the total cost of electricity services, a utility would work to implement DSM measures until their cost of saved energy reached the cost of supplying and delivering electricity.

In practice, it makes a lot of sense to choose DSM measures even when they significantly exceed the cost of supplying and delivering electricity. There are several reasons for this. First, and most understandably from the utilities perspective, is that DSM measures almost always cut back on the peak load, which is almost always more expensive

Figure 4: Cost of Saved Energy Curve Showing US Energy Efficiency Achievable Potential Energy Savings in 2010 – All Sectors. Source: (Gellings, Wikler, and Debyani 2006).



than the base load. Second, adding DSM measures has to be compared with the costs of adding additional generation capacity together with the cost of any transmission investments that this new generation requires (utilities are fond of ignoring transmission costs in these comparisons). Thirdly, DSM measures, because of their distributed and often passive nature, often are less risky than supply measures. Finally, DSM measures often have a significantly lower societal or environmental cost (such as carbon emissions) over new supplies which, as we've pointed out before, are very hard to quantify and hence are not adequately included in the "costs" of the various measures. Because of this inherent attractiveness of DSM measures, one planning tool is to legislate that DSM measures are given an inherent advantage over supply measures. This is an approach taken by the group of states in the Pacific Northwest of the U.S., which requires the Bonneville Power Administration to choose an efficiency measure over a supply measure up to the point where it is 10% more expensive to do so.

CREATE CANDIDATE INTEGRATED RESOURCE PLANS

With data in hand on supply and demand side options and their attributes, the next step is to prepare candidate plans.

Software tools are available that can generate and evaluate many different supply/demand combinations. These include the PROVIEW II™ system developed by Resource Management Associates, as well as Strategist and System Optimizer developed by Ventyx.

Regardless of the software package chosen,

> "The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. … By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies."(State and Local Energy Efficiency Action Network. 2011)

Unfortunately, in the U.S. it is common practice by some utilities (PGE in Oregon, Xcel in Colorado, Entergy Arkansas, and Georgia Power) to use an IRP process that does not really compare supply resources and DSM on an equal footing to allow the strength of energy efficiency to come to the fore. These utilities simply deem a certain amount of DSM to be available (often only sufficient to cover the quantity of energy efficiency required by state statute). They reduce the load forecast by that amount, and then fill the void with supply side resources – even if the deemed amount of DSM neglects potential savings that are less expensive than supply-side resources (Lamont and Gerhard 2013). This practice appears to go against the "low cost planning" spirit of IRP by forgoing energy efficiency and DSM resources with lower societal costs.

In the U.S., utilities that conduct "real" IRPs that compare supply and demand side measures on an equal footing include the mega-utility PacifiCorp (which serves 6 western states), and Puget Sound Energy in Washington State. Utilities in California and Connecticut are subject to loading order requirements which require that utilities must first meet electrical load growth through energy efficiency and demand response. Only after all cost-effective demand side measures have been taken may utilities consider adding conventional supply-side generation technologies (*Connecticut Public Act*; *California Assembly Bills 1890 and 995*). Similarly, Washington State's Initiative 937, passed by voters in 2006, requires that electric utilities serving more than 25,000 customers must deploy all cost-effective energy conservation potential. Utilities are required to conduct a Conservation Potential Assessment (CPA) every other year which catalogs all achievable cost-effective energy conservation in their service area.

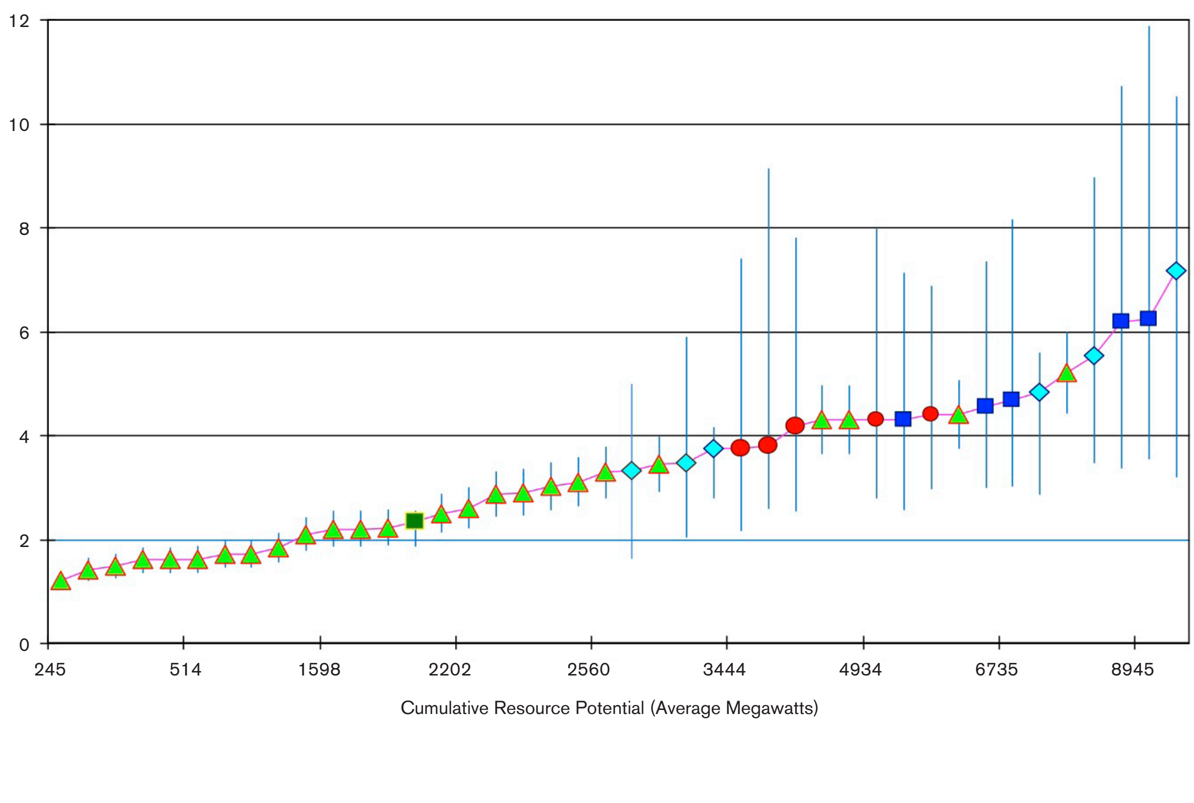
The best IRP processes also include consideration of risk. The Northwest Power and Conservation Council (NPCC) completes comprehensive 20-year IRPs for the US Pacific Northwest region comprising Washington, Oregon, Idaho, and Montana to guide the Bonneville Power Administration (BPA) and other customer utilities in the region. As of 2010, Initiative 937 requires utilities' conservation plans to be consistent with the NPCC conservation plan. In developing its IRP, the NPCC runs over 700 different scenarios that consider a variety of risks including natural gas prices, snow pack (since the region uses mostly hydropower), and the future presence or absence of a carbon tax.

SELECT THE PREFERRED PLAN

With candidate IRPs developed, the next step is to select among them to arrive at a preferred plan and several contingency plans that may become more attractive as conditions change (e.g. load growth is lower or higher than expected). The selection process involves setting the evaluation criteria, evaluating and ranking the candidate plans according to the criteria, and then using the results of the evaluation to decide on the preferred plan and contingency plans to adopt for implementation (or further study). Selection criteria will generally be similar to the basic objectives generated by stakeholders at the beginning of the planning process. A description of the preferred plan typically includes an implementation schedule of activities such as building a new power plant, or starting a DSM program.

Selection of a preferred IRP should be done systematically if the result of the planning process is to be credible. There are a variety of methods used in practice ranging from listing each attribute of each plan in a large matrix

Figure 5: Cost and risk for 40 resource options selected in the NPCC's 5th regional plan. Cumulative capacity is shown on the X-axis, and real levelized cost (in year-2000 U.S. cents) on the Y-axis.



(for example, displayed on a large sheet of paper in a conference room) and systematically eliminating candidate plans (noting why each is eliminated), to quantitative approaches involving "Multiple Attribute Analysis" or "Multi Criteria Analysis" that weigh attributes or criteria according to the importance ascribed to them by stakeholders.

Whatever approach is used to decide among plans, it is ultimately the people involved in the planning process who will decide which plan is to be adopted and implemented. Clear ground rules are needed to help guide and document the process in a transparent and complete manner, so that others may review the decisions made along the way.

DURING IMPLEMENTATION OF THE PLAN, MONITOR, EVALUATE, AND ITERATE

Deciding on a preferred IRP plan is a key decision, but not the end of the IRP process. One crucial choice is who will implement DSM elements of the IRP. In some cases, utilities implement DSM since they already have extensive information on their customer base, have access to customers through communication channels such as bill inserts, and may have the ability to scale up human resources to roll out a full-scale DSM programs. In some cases this works well. In other cases, the culture and incentives of conventional utilities have not been compatible with deploying DSM – after all, utilities earn revenues through sales of electricity. Programs that help people save electricity can lower utility revenues, and utilities are composed largely of professionals whose careers and identities focus on building or operating power plants. Implementation of DSM through an IRP has very successfully been carried out by non-utility partners, for example by Efficiency Vermont (which deploys energy efficiency services throughout the U.S. state of Vermont) and the Oregon Energy Trust (which performs a similar function in the state of Oregon).

DSM programs and plans are typically monitored by the utility or other program administrator to understand the demographics of participating customers, energy and peak savings achieved, and costs of rolling out programs. This data and evaluations are essential for maximizing program effectiveness and choosing DSM measures for future IRPs.

Implementation involves both benchmarking the performance of utilities and other program administrators against the IRP, as well as revising the IRP as conditions change and new information becomes available. Costs, availability, and performance of supply-side and demand-side resources may differ considerably from assumptions in the preferred plan. Monitoring of the performance of the electric system, with particular focus on additions called for in the resource plan, provides critical information for the next iteration of the IRP.

Micro-hydro transmission line being installed by the Ladakh Ecological Development Group (LEDeG) with Honupatta villager in Ladakh, India. Photo by Dipti Vaghela.

To address the divergence between plan and reality, major revisits to IRPs are typically scheduled every two to five years, with mid-course corrections to respond to changing conditions. When a development occurs that was not adequately foreseen or considered, it is important to revisit the plan, rather than rigidly abiding by it, or, in the alternative, bypassing it.

Examples of “Best Practices” IRP

United States

1. PACIFIC CORP

Pacific Corp is a huge US utility, serving 1.7 million customers across six states: Oregon, Washington, California, Idaho, Utah, and Wyoming. Five of these states have IRP or other long-term planning requirements.[12] Pacific Corp uses a portfolio modeling process based on software called System Optimizer which optimizes portfolios, performs cost assessments on these optimized portfolios, and conducts risk assessments on each portfolio. Pacific Corp considers 67 different input scenarios that include variations in transmission system configuration, CO2 price levels, natural gas prices, and renewable energy policies. Based on 100 different portfolio simulation runs, the top portfolios are chosen that have the lowest average portfolio cost and lowest ‘worst-case’ cost.

Energy efficiency is considered as a supply-side resource, rather than as a reduction to load, thus allowing energy efficiency to compete with supply side resources on a level playing field (Wilson and Biewald 2013). Energy efficiency data include information on 18,000 different measures across residential, commercial and industrial customers. Pacific Corp completes an IRP every odd-numbered year. In the modeling of Pacific Corp’s 2013 IRP preferred portfolio, energy efficiency resources meet 67 percent of currently forecasted load growth through the year 2022 (Pacific Corp 2013).

A criticism of the Pacific Corp 2011 IRP by the Sierra Club was that the input assumptions and analysis related to its fleet of 26 coal-fired boilers (making up about two thirds of its generation) are weak. In particular, federal air pollution standards require the company to spend $1.57 billion in pollution control measures from 2011 to 2020. Pacific Corps was criticized for not fully accounting for these costs in its 2011 IRP (Wilson and Biewald 2013) – leading to the high probability that the 2011 IRP was not fully optimized. The most recent (2013) IRP appears to address the environmental investment costs of coal (Pacific Corp 2013, Chapter 7, section 7.1 “Modeling Coal Unit Environmental Investments) but details are in a confidential “Volume III” of the IRP and it remains to be seen whether Pacific Corps analysis and data on these coal costs are sufficient. This raises the key point that an IRP is only as good as the assumptions used in the models; and highlights the key necessity of a transparent process that provides for inclusion of civil society groups.

2. NORTHWEST POWER CONSERVATION COUNCIL

The Pacific Northwest Electric Power Planning and Conservation Act (passed by Congress in 1980) established the Northwest Power and Conservation Council, which is charged with developing plans every five years to ensure an adequate, efficient, economical, and reliable power supply for the region. Working with regional partners and the public, the Council evaluates energy resources and their costs, electricity demand, and new technologies to determine a resource strategy for the region.

The NPCC’s Sixth Plan recommends aggressive deployment of energy efficiency, indicating how the region can meet 85 percent of new demand for electricity during the next 20 years. Figure 5 below shows the options selected in the NPCC’s 5th plan (which also called for meeting approximately 85% of new growth with energy efficiency). The blue error bars represent risk, expressed as the potential for substantially higher or lower than expected cost. Of the 21 lowest cost power sources selected by the NPCC’s comprehensive modeling effort, 20 are energy efficiency measures (green triangles), with one cogeneration project (blue square). It is noteworthy that in addition to being lowest cost (most under 3 cents per kWh) the energy efficiency measures are also substantially lower risk than new supply.

South Africa

South Africa is one of the few non-OECD countries that conducts an IRP. The country's 2010 IRP is a subset of the National Energy Plan, which is developed by the Department of Energy (Electricity Governance Institute 2013). It laid out the proposed generation new build fleet for South Africa for the period 2010 to 2030. While the 2010 IRP was not a "full" IRP in the sense of comparing demand side and supply side measures on an even playing field (Eberhard 2013), it did include a public participation process (November/December 2010) which led to substantial increases in renewable energy in the plan, as well as an upward adjustment of investment costs for nuclear by 40% based on recent construction experience. The revised plan called for a substantial percentage (42%) of new generation to come from renewable energy.

The revised plan includes 9.6 GW of nuclear; 6.3 GW of new coal; 17.8 GW of renewables (split mostly between solar PV at 8.4 GW and wind also at 8.4 GW); and 8.9 GW of other generation including hydro (2.6 GW), combined cycle gas turbines (2.4 GW), and single cycle gas peaking plants (3.9 GW). The IRP included a public process inviting interested parties to submit written comments or present at workshops in a variety of cities in the country (Peters 2011).

Criteria used in optimizing the IRP included reducing carbon emissions; reducing water usage; creation of local jobs; Southern African regional development and integration; and security of supply. The IRP translates into actions on the ground in the following way: the regulator cannot license new generation unless the Minister has made "a determination" in relation to the IRP – although exceptions are allowed. (Eberhard 2013)

The South African IRP is not without critics. For example the Electricity Governance Initiative of South Africa issued a report, called 'Smart Electricity Planning,' which argues that South Africa could save in the region of R162 billion (about 17 billion USD) if smarter expenditure in energy infrastructure was made, including more energy efficiency; no nuclear power; a reduction in fossil fired power plants; and more renewable energy (EGI 2013).

Community-scale solar panels in rural Haiti. Photo courtesy of Sun Energy Power International.

Conclusion: Aligning Power Plans Towards Environmental and Societal Goals

IRP is a public process in which planners work together with stakeholders to establish scope, investigate options, prepare and evaluate integrated plans, select preferred plans, as well as establish mechanisms to monitor, evaluate, and iterate plans as conditions change. In contrast to the limited choices considered in conventional power development planning processes, IRP considers a full range of power sector investments to meet new demand for electricity, not only in new generation sources, but also in transmission, distribution, and – importantly – demand-side measures such as energy efficiency on an equal basis. IRP plans use long-term (20-30 year) planning horizons and include careful consideration of risk. Best practice IRPs integrate environmental and other external costs and benefits.

When done properly, IRP provides a structure and an opportunity for utility systems and stakeholders to learn and to develop plans in a co-operative atmosphere. Ultimately, better decision-making processes result in power plans more closely aligned with societal goals. Although a comprehensive IRP process requires a substantial commitment of time, IRPs lead to better outcomes: lower cost electricity, lower risk from price volatility, and lower social and environmental impact – through emphasizing services (cooling, heating, lighting, etc.) rather than kilowatt hours of electricity alone, through evaluation that considers full social and environmental costs rather than narrow consideration of only utility finances, and through choices that lower cost to society under a full spectrum of scenarios. Generally, these better outcomes involve considerably highger investment in energy efficiency and demand-side management than utilities would deploy without an IRP process.

Row of electricity towers transmitting hydropower in Quebec, Canada. Photo courtesy of Google Images.

Further Reading

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NOTES

1. Not all countries use the term "Power Development Plan". "Long Term Power Planning" or "Power Sector Master Plan" or similar terms are also used.
2. Energy efficiency (EE) refers to technologies that use less energy to perform the same task. Demand side management (DSM) may include EE and refers more broadly to steps that reduce energy or peak power demand through a variety of means including education, financial incentives, or technologies that help shift demand to non-peak times.
3. While the focus on power sector investment planning is essential, if one's goal is to promote efficient use of electricity to reduce the costs and impacts of power sector infrastructure development, then it is also important to pay attention to macro-economic planning and policies. Part and parcel of conventional practices that get countries into power sector trouble are economic policies that encourage highly energy-intensive (and generally highly polluting) industries to locate in their borders. This drives up power consumption and forces power plant decisions that hurt people. It is important to focus on promoting an efficient, high-value, competitive economy, and on policies such as small power producer programs or feed-in tariffs that allow clean energy entrepreneurs to compete in providing services that people need most. European countries (Germany in particular) have long been leaders in this space, but some developing countries (Thailand and Malaysia in South East Asia, Tanzania and Uganda in Africa) have developed good working policy frameworks that have led to significant deployment of customer-owned renewable energy.
4. It is not rare that committee members have incentives to inflate forecasts because they benefit in one way or another from building new power plants.
5. An appropriate level of reserve margin is often determined based on Loss of Load Probability (LOLP) (a measure of the probability that a system demand will exceed capacity during a given period; often expressed as the estimated number of hours or days over a period of a year or more) not exceeding a certain threshold. An optimal threshold is where the cost of achieving increased reliability (reduced LOLP) does not outweigh the cost of supply disruptions ("outage cost").
6. Hydropower is often so site-specific with respect to capacity, location, and cost, that hydropower plants are added into the modeling exogenously as "predetermined choices".
7. WASP was developed in 1972 by the Tennessee Valley Authority eight years before the video game Pac Man was released, in the primordial ages of both power sector planning and computer programming. The program is given away for free by the International Atomic Energy Agency (IAEA) and is reportedly in use in over 80 developing countries (Tantirimudalige 2013).
8. http://www.ventyx.com/en/enterprise/business-operations/business-products/strategist
9. http://www.ventyx.com/~/media/files/brochures/system-optimizer-datasheet.ashx?download=1
10. http://mjperry.blogspot.com/2012/05/commercial-natural-gas-prices-drop-to.html
11. An end-use model of household electricity use might include separate estimates of electricity used for lighting, water heating, space heating, air conditioning, fans, cooking, entertainment, and other appliances. Using the example of air conditioning, one can specify a relationship between end-use variables:

    Electric energy use for air conditioning = number of households * fraction of households with air conditioners * amount of cooling required per household * energy intensity (kWh per unit cooling delivered) of average air conditioner model in use.

    In this example, one can forecast energy usage by projecting each of the four parameters on which air conditioning electricity usage depends. End-use forecasts can be prepared using spreadsheet software, or using customized forecasting software packages. The Long-range Energy Alternatives Planning System (LEAP) is an excellent software package for end-use electricity modeling. Single-user licenses are free to organizations in developing countries. "LEAP: The Long-range Energy Alternatives Planning System." Accessed May 1, 2013. http://www.energycommunity.org/default.asp?action=43.
12. For example, in 2006, voters in Washington State passed Initiate 937, which requires that electric utilities with more than 25,000 customers undertake all cost-effective energy conservation measures. Utilities are required to conduct a Conservation Potential Assessment (CPA) every other year which catalogs all achievable cost-effective energy conservation potential in their service area.

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