Comments to the Idaho PUC regarding the Idaho Power 2013 IRP
By Courtney White

A fundamental role of the IRP process is to consider what the future may look like and what alternative paths forward would best serve needs. With regard to energy, we are facing new levels of change and uncertainty. The 2013 IRP process has not yet adapted to evaluate the impact of technology changes and the value of option-preserving alternatives, as explained by the comments in this document. This increases the need for Idaho Power, the public, and the PUC to give diligent and open-minded consideration to alternatives at any decision point before further vesting in specific resource alternatives.

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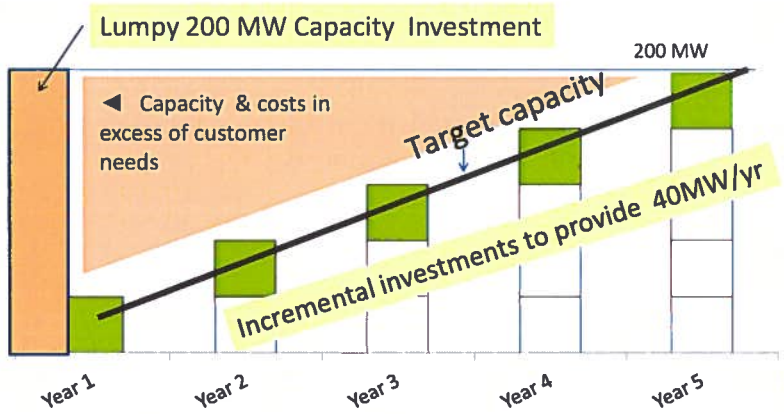
A. Risks, Uncertainties, and the Value of Flexibility

The IRP addresses risk in its section Risk Analysis and Results. This analysis identified only four variables: natural gas prices, customer load, hydroelectric conditions, and a carbon adder. There are numerous variables that effect the value of alternative resources that are not adequately valued in the comparison of alternative resources. Here are some examples:

1. The value of staging investments to meet demand. Resources vary in the degree to which investment can be staged to best fit demand growth. In the Resource Alternative Analysis, the 2013 IRP does not address the advantages of delaying the fixed and variable costs associated with resources which can be staged incrementally to fit the demand growth.

Issue: The cost of excess

An analysis of alternative resources should reflect savings gained when capacity can be installed incrementally to meet demand growth, thereby delaying capital costs, overhead, and variable costs.

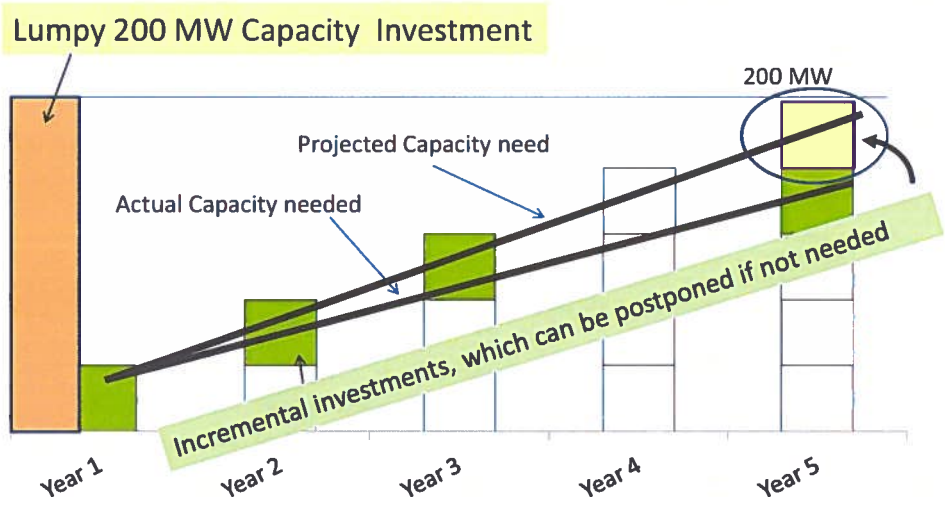


This chart is for exemplary purposes. The flexibility to stage capacity additions to fit demand growth is specific to each alternative.

2. The value of flexibility when forecasts are wrong. When the future is uncertain, options which preserve flexibility have higher value. The IRP does not adequately address this fundamental difference in alternative paths. If, for example, actual demand growth were less than projected, alternatives which allow the utility to postpone additional investments would be advantageous. The cost of adding unnecessary capacity could be avoided. There is a financial value to flexibility which the IRP process is failing to capture in its comparison of alternatives.

Issue: The lumpier the investment, the higher the cost of mis-forecasting.

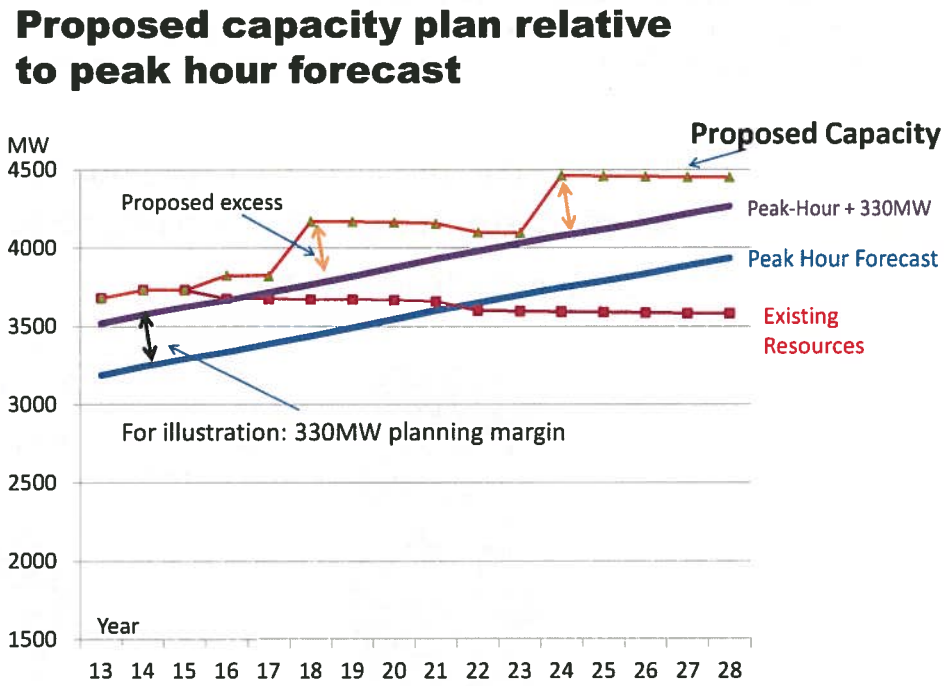
If actual requirements are less than projected, some alternatives preserve the option to adapt, which could save customers significant $ by preventing investment in unnecessary infrastructure.



This chart is for exemplary purposes. The flexibility to stage capacity additions to fit demand growth is specific to each alternative.

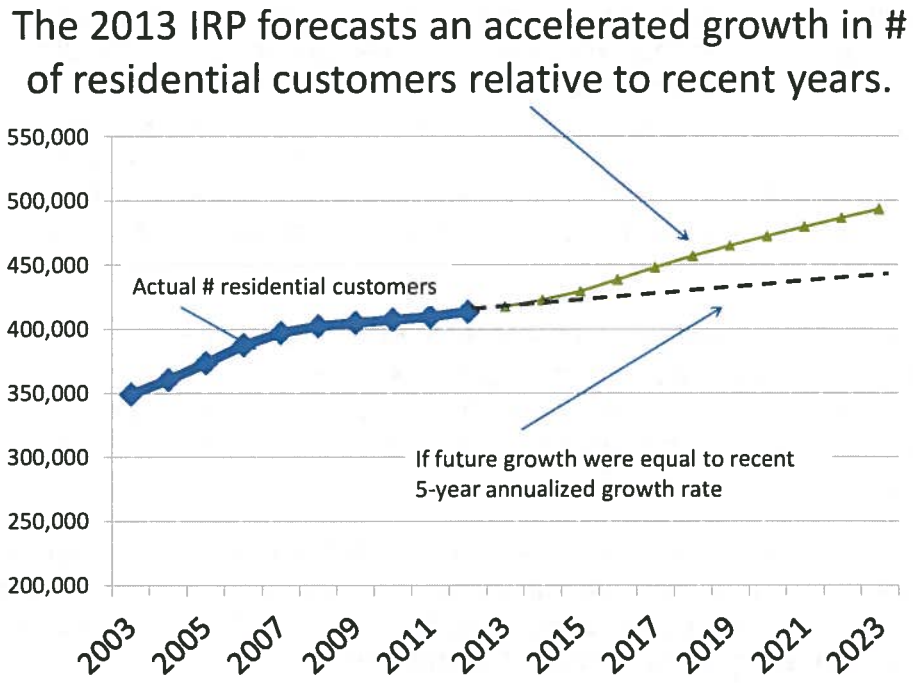
The above chart is hypothetical for illustration only. Below is a chart showing the proposed capacity additions relative to the forecasted peak hour need as described on pages 107-108 of the 2013 IRP.

Note that, if in year 17 the demand were lower than projected, the proposed excess capacity in year 18 is even greater. Note also that the proposed capacity plan assumes 150 MW of Demand Response in year 16 and 17, which goes to zero in year 18.



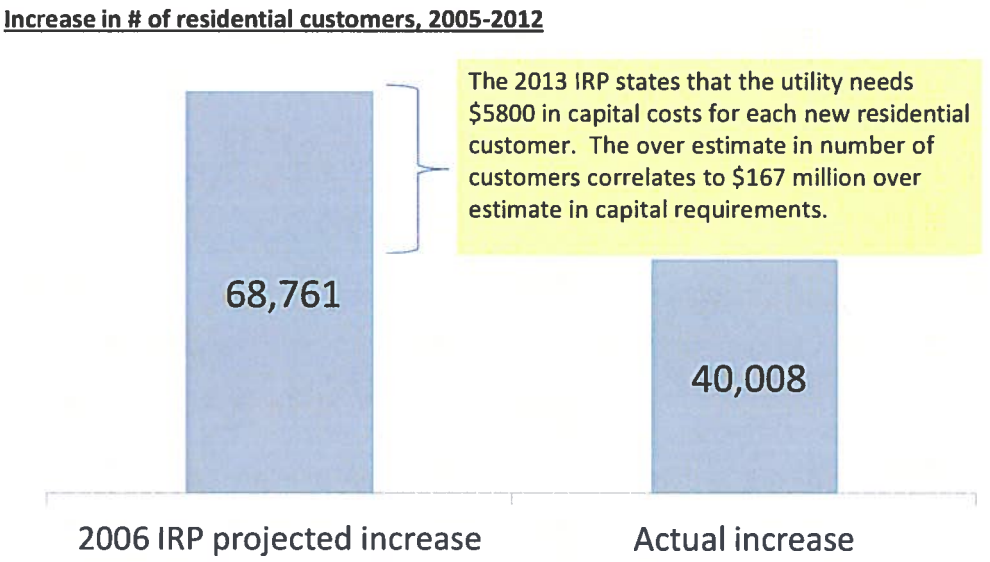
3. **The demand forecast is more uncertain than presented.** There are numerous factors and assumptions which go into the demand forecasting, and we ratepayers have limited representation as the Company formulates its projections. As a test of whether the process is objective and the range of uncertainty is being adequately presented, let's consider the projected growth in number of residential customers.

Over the most recent 5 years (2012 / 2007), the annualized growth in number of residential customers has been **0.8%.** The 2013 IRP projects residential customers to grow by an annualized rate of **1.6%** over the coming five years. This projection seems aggressive.



To verify whether the methodology has worked in the past, let's look back at a prior IRP. In the 2006 IRP, the number of residential customers was projected to grow by 68,761 from 2005 to 2012. This projected increased was 72% higher than actual.

For example, the increase in the number of residential customers grew much less than projected in the 2006 IRP



Similarly, consider the hypothetical that the growth rate in number of residential customers is constant rather than accelerated in the coming years. The 2013 IRP projects the number of residential customers to be 494,980 in 2018. If the growth rate in residential customers continues at the same rate as the prior 5 years, the projection would be in excess of actual by over 60,000. At $5800 per customer, this error margin would correlate with approximately $350 million in capital costs. This analysis is not a prediction but a demonstration of the value associated with alternative paths that mitigate the risk of forecast errors.

The 2013 IRP identifies Low and High growth load projects as a means of addressing the range of uncertainty. For example, the "Low" scenario (page 14, Appendix A) is 4.5% less than the "Expected" scenario in 2017. Is that an adequate range? With regard to the example variable of residential customers, the actual number in 2012 was 6.5% less than projected in the 2006 IRP.

The future is not becoming easier to predict but more uncertain. **An alternative which allows investments to be staged more closely with actual demand has value because it reduces the risk of investing in excess capacity. The 2013 IRP is inconclusive because it does not adequately account for this value.**

4. The cost of contingency capacity requirements were not adequately evaluated.

The 2013 IRP on page 106 describes the level of excess capacity needed:

> Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility.

The level of excess capacity needed for contingency planning varies by alternative resource. The Resource Alternatives Analysis includes reliability risks for some alternatives; for example, the risk that the sun doesn't shine translates into a cost in the IRP's comparison of solar to alternative resources. However, the cost of risks associated with disrupted operation of the Bridger coal facilities is not integrated into the cost of continuing to rely on these alternatives. The level of contingent capacity varies across different resource strategies, and a diversified array of resources will tend to have lower risk than reliance on large facilities, particularly ones that are minority-owned. The 2013 IRP is inconclusive because risks are selectively translated into costs for some alternatives yet not for others.

B. The IRP process did not adequately address expected changes

The IRP process is misleading by presenting a 20-year forecast that omits trends and technologies which have a material impact on the forecast.

1. **The IRP process did not incorporate the value of projected improvements in storage technology.** The IRP process did not adequately address the full benefits of storage, the wide range of options, or the changing nature of this technology.

The PUC in California, for example, recently announced its requirement that the state's large investor-owned utilities must buy a total of 1.3 gigawatts of storage. The process arriving at this decision did not isolate the cost effectiveness of storage as a new resource alternative based on today's technology and costs, instead it considered the impact of improved cost effectiveness for renewable resources, the need for emergency capacity, and the impact on grid optimization. The San Francisco Chronicle quotes one commissioner in its October 17 coverage http://www.sfgate.com/business/article/CPUC-s-new-energy-storage-rules-aim-to-aid-grid-4904875.php:

> "Energy storage has the potential to be a game changer for our electric grid, and I fully support the goals of grid optimization, integration of renewable energy and reduction of greenhouse gas emissions," said Commissioner Mark Ferron.

Storage technology will improve, and Idaho Power's rate payers deserve to benefit from these improvements. As reported on UPI.com, posted October 18, 2013:

> "Integrating renewables is complex, and the complexity is increasing as more solar and wind comes online," Carla Peterman, also a CPUC commissioner, who previously

> served on the California Energy Commission, was quoted as saying by the San Jose Mercury News.
>
> "Storage has a lot of potential, but there's no one solution. We need to develop this market to see what the potential is," Peterman said.
>
> California's mandate is expected to spur innovation in emerging storage technologies, from batteries to flywheel energy storage, a technique that accelerates a rotor to high speeds thus creating a kinetic battery.
>
> "This is transformative," Chet Lyons, an energy storage consultant in Boston told the Mercury News. "It's going to have a huge impact on the development of the storage industry, and other state regulators are looking at this as a precedent."

During the IRP planning horizon, nations around the world will be investing to provide electricity to growing populations, driving improvements in distributed generation and storage technology, which will improve the cost effectiveness of solar and wind here in Idaho. Avista, for example, notes in its 2013 the potential value of storage (section 6-10):

> Increasing amounts of solar and wind generation on the electric grid makes energy storage technologies attractive from an operational perspective. The technologies could be an ideal way to smooth out renewable generation variability and assist in load following and regulation needs. The technology also could meet peak demand, provide voltage support, relieve transmission congestion, take power during over supply events, and supply other non-energy needs for the system. Over time, storage may become an important part of the nation's grid.

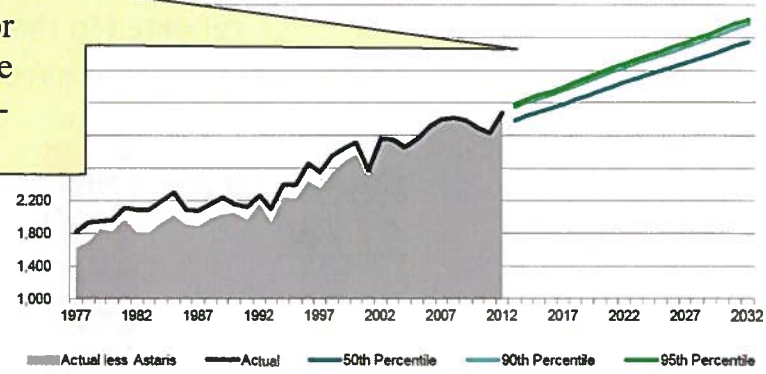
The flexibility to take advantage of technology improvements has financial value, which should be considered in comparing alternative resource strategies.

2. The opportunities for demand management are not adequately considered. Time-of-use pricing, for example, has potential to substantially change the peak load forecast. As utilities around the world strive to link pricing to costs, behaviors change and new markets are created for technologies that enable customers to optimize the timing of their electricity demand. Rather than project strong and unchecked growth in peak demand, as shown in page 29 of Appendix A (below), the IRP process should give greater consideration to strategies and trends that could better manage the shape of the demand curve over the 20-year planning horizon.

Table 10. System summer peak load growth (MW)

Growth	2013	2017	2022	2032	Annual Growth Rate 2013–2032
95th Percentile	3,382	3,596	3,881	4,418	1.4%
90th Percentile	3,344	3,555	3,835	4,365	1.4%
50th Percentile	3,189	3,387	3,651	4,147	1.4%

In a free market, a firm would not forecast unmitigated growth in peak demand for the next 20 years. Competitive pressure would prompt firms to pursue demand-side alternatives to reduce peak loads.



3. Energy efficiency was not adequately considered as a resource. The 2012 Idaho Energy Plan specifically instructs Idaho and Idaho utilities to consider energy efficiency as a resource, as stated on page 9:

> When acquiring resources, Idaho and Idaho utilities should give priority to cost-effective and prudent: (1) conservation, energy efficiency, and demand response; and (2) renewable resources, recognizing that these alone will not fulfill Idaho's growing energy requirements and that these resources play a role in addition to conventional resources in providing for Idaho's energy needs.

However, the Resource Alternative Analysis, for which the results are presented on page 84 of the 2013 IRP, does not identify conservation, energy efficiency, or demand response as resources which could be compared to the alternatives presented. In the portfolio of resources considered in Section 8, energy efficiency was not treated as a scalable resource. Instead, it is presented as a reduction in load. The IRP process should follow the state guideline to give priority to energy efficiency as an alternative when acquiring resources.

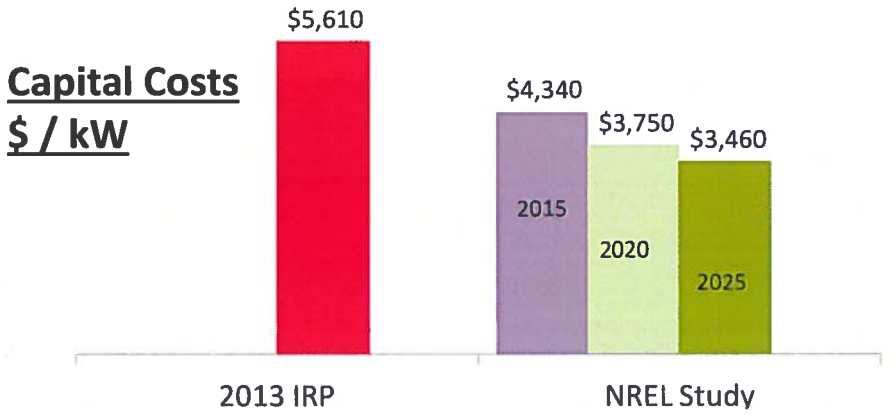
4. The Resource Alternatives Analysis of solar PV included poor assumptions.

- **The analysis assumes solar panels exclusively face south**, which is less efficient for meeting peak demand than facing southwest. Idaho Power only considered alternatives in which the utility, not the customer, owned the solar panels. This begs the question - why would Idaho Power choose to orient the panels in a manner that makes them less cost effective under the methodology Idaho Power uses to evaluate this resource?

- **The cost estimates for solar presented in the 2013 IRP are high.** Residents and local Idaho solar installers are scratching their heads at how high the estimates in the IRP are relative to current and expected market prices. Even if one looks at the source data used by the IRP, *The NREL Cost and Performance Data for Power Generation Technologies*, the costs appear high. For example, below is a comparison of the capital costs which the

2013 IRP used for assessing Distributed Solar PV (page 85) relative to the capital costs presented in the NREL source data, page 38.

The 2013 IRP assumes Plant Capital for Distributed Solar PV is much higher than the Capital Costs for Residential Solar PV reported in the NREL source data.
Again, projected decreases are not reflected in the IRP.



Note: The NREL study presents data in constant 2009 dollars while the IRP presents data in 2013 dollars, though this does not explain substantially higher cost estimates used by the IRP

Given the average price of a solar PV panel has declined 60% since the beginning of 2011 (source: *Solar Energy Facts: Q2 2013*, by SEIA), the substantially higher estimates used in the IRP might be explained if the 2013 IRP used old data. In order to adequately consider solar PV alternatives, the IRP process should be forward-looking through use of expected prices, and should tap the expertise of local professionals and local research.

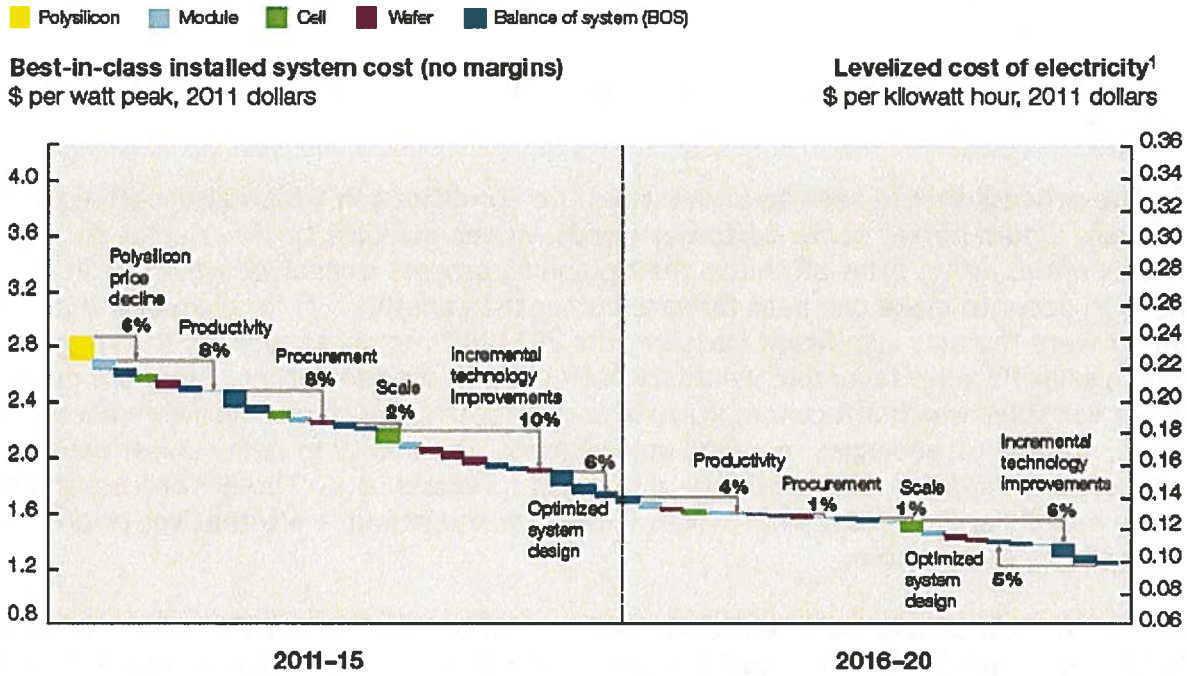
- **Solar PV costs are projected to continue declining.** The NREL source data used by the IRP projects declines in solar PV. McKinsey & Company published the results of its in-depth study of solar PV in the 2012 McKinsey Quarterly, which states:

  > PV prices are expected to continue to fall - even though subsidies are expected to dry up - as manufacturing capacity doubles over the next three to five years and underlying costs drop by as much as 10 percent annually until 2020. Indeed, our analysis suggests that by the end of the decade, costs could decline to $1 per watt peak (Wp) for a fully installed residential system.

Below are McKinsey & Company's projections of installed system costs of solar PV:

Industrialization will yield significant cost reductions.

c-Si multicrystalline solar-photovoltaic system



[1]Levelized cost of energy; assumptions: 7% weighted average cost of capital, annual operations and maintenance equivalent to 1% of system cost, 0.9% degradation per year, constant 2011 dollars, 15% margin at module level (engineering, procurement, and construction margin included in BOS costs).

Source: Industry experts; Photon; GTM Research; National Renewable Energy Laboratory; US Energy Information Administration; Enerdata; press search; company Web sites; McKinsey analysis

The IRP process is unable to validate what alternatives most cost effectively meet customer needs given it did not objectively consider the current and declining costs of alternatives and the value of flexibility to adapt to actual demand, stage investments, and take advantage of technology improvements.

C. Given increased uncertainty, new approaches are needed

The energy sector is facing new levels of uncertainty, thus the planning process needs to adapt. Below are a few notes on how to do so.

1. The process should value flexibility. When analyzed purely on costs, bulk buys and "lumpy" investments typically look attractive due to the economies of scale. However, the ability to stage investments to meet demand, the ability to avoid unnecessary investments when forecasts go awry, the ability to leverage improvements in technology, and the ability to reduce the level & cost of capacity planning margin *all have value*.

2. New approaches to valuing storage should be adopted. Avista summarized this challenge and opportunity in its 2103 IRP, section 6-10:

> One of the biggest obstacles to energy storage is quantifying and properly valuing its benefits. At a minimum, the value of storage is the spread or difference between the

> value of energy in on versus off-peak hours (load factoring), minus the losses. Since the technology can meet regulation, load following, and operating reserves, there is value beyond load factoring. Valuing these benefits requires new system modeling tools.

The Idaho Power IRP process would also benefit from new system modeling tools for valuing storage.

3. The process should seek to understand the conditions in which alternative paths forward would better serve customer needs. As the complexity of variables and range of uncertainties grow, firms often use their planning process to analyze what conditions would have to occur to make one path forward better than another. If, for example, the carbon adder were the only significant variable, the 2013 IRP's effort to identify the trigger point at which solar PV were favorable would be useful. As described earlier, there are numerous other variables which affect the ultimate cost effectiveness of alternatives - declining PV costs, storage technologies, demand management, the ability to delay investment in unnecessary capacity, the reliability of demand forecasts, etc. The IRP process should think more broadly and consider what-would-it-take for the resource alternatives prioritized by state policy to be viable.

4. The process should be a venue for seeking out better options. The above what-would-it-take approach is not only a tool for valuing alternatives in the face of uncertainty but also for *building understanding and for innovating better solutions*. The 2012 Idaho Energy plan encourages us to consider these opportunities and maintain flexibility to leverage them:

> The Plan also encourages monitoring new energy technologies and cooperation between stakeholders to allow us to more quickly respond to possible opportunities and risks.

Rather than omit discussion of transformative changes in the energy sector, our IRP process could become a venue for professionals within and outside of Idaho Power to build understanding of those changes and to explore opportunities for all stakeholders to benefit from them.

5. The process and financial incentives should adapt to enable more objective consideration of alternatives. As an investor owned utility, Idaho Power has an accountability to optimize its return on capital. If the financial incentives available to the company favor investments in infrastructure, it is challenging for the company to be objective in its consideration of alternatives. This problem is magnified by the increasing complexity and subjectivity of planning for an uncertain future. I believe that Idaho Power and other Idaho stakeholders have the capacity to be leaders in exploring incentive structures that enable both the company and its ratepayers to benefit from more objective pursuit of alternative resources.

Because the IRP process did not adequately identify or value alternative paths forward, the need for diligent and open-minded consideration of alternatives is paramount before making further commitments to specific resource strategies, such as the proposed investments which presume a continued reliance on operation of the Bridger facilities.