BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 66

In the Matter of	)	
Portland General Electric	)	INITIAL COMMENTS OF THE
2016 Integrated Resource Plan	)	NW ENERGY COALITION
	)	

The NW Energy Coalition (Coalition) is pleased to offer comments on Portland General Electric (PGE)'s 2017 Integrated Resource Plan (IRP). It is currently an exciting but challenging time to be involved in electric utility resource planning as the future of the industry is changing rapidly in many ways, from supply-side technology and cost -- to an increasing reliance on demand side options that are quickly advancing -- to changing markets and business models. Planning under uncertainty is never easy, but current circumstances exacerbate these challenges.

In most of the underlying studies and analyses supporting the 2016 IRP, PGE offers innovative studies (renewables integration, flexible capacity, and others) that address current developments in the electric utility industry. The Coalition is impressed with this foundational work and has recommended several of these studies to other utilities throughout the region in recent months.

Our initial comments focus on a critical review of the portfolio analysis, scoring metrics and associated risk analysis, and related action items. We express support for the robust portfolio analysis examining early action procurement of renewable resources. The majority of our comments highlight deficiencies with the Company's portfolio construction and analysis that led the Company to an outdated reliance on large fossil fuel generation resources that require long-term financial commitments.

I. Portfolio Analysis

The Company's treatment of supply side options and modeling methodology results in an IRP that favors the selection of a preferred portfolio heavy in large long-term (30-year or more) investment in new natural gas resources by underrepresenting other resource options. The following sections discuss how the IRP supply side assumptions and modeling methodologies bias results in favor of natural gas.

Proxy Resources

The IRP modeling methodology places too much reliance on the use of large, fossil fuel resources – underrepresenting the potential contributions from demand side resources, renewables, hydropower, market purchases and even smaller natural gas fueled generating options. In the IRP, "generic capacity" is modeled as a natural gas single cycle combustion turbine (SSCT) and the need for "efficient capacity" is modeled as a natural gas combined cycle (CCCT). This overreliance on proxies, consistent across ALL portfolios, fails to adequately consider all known resources, as required in the Commission's IRP Guideline 1a. The renewal or acquisition of new hydropower resources are not modeled, and demand side resource decisions are made prior to modeling and risk analysis with no effective attempt to test higher levels of these resources. Furthermore, assumptions about market purchases, including limited availability throughout the year, skew modeling results.

Hydropower

PGE currently has over 180 aMW of hydropower contracts expiring over the next five years that may be available for renewal or renegotiation[1]. Additionally, new hydropower products may currently be available in the market from a variety of sources, including Bonneville Power Administration, Chelan PUD, and others. Hydropower's high availability and flexibility make it a good fit for PGE's resource needs.

Despite potential availability in the market, PGE failed to model hydropower resources in its portfolio analysis. In fact, the IRP chapter discussing supply options presents no analysis of hydropower resources; these resource options are completely absent from the chapter[2]. No scenarios tested the potential contribution of hydropower resources from either contract renegotiations or new sources. The Coalition is concerned that without IRP modeling results to inform resource procurement activities, it will be difficult to evaluate the relative contributions a hydropower purchase can provide to PGE's system needs relative to another resource. Additional analysis including one or more portfolios with hydropower resources would help inform the IRP analysis.

Market Purchases

IRP Order #14-415 (pp. 5-6) in the PGE 2013 IRP directs PGE to include portfolios that include "maintaining an open position." PGE asserts that this direction is met because they consider "two portfolios with different open position levels"[3]. PGE does not state which two portfolios they are referring to, however, all modeling scenarios include a market limitation of 200 MW during all time frames across the year except summer peak times, which have no market availability[4]. Perhaps PGE is referring to Portfolio 1, which

[1] PGE IRP, Appendix D, pp. 379-380
[2] PGE IRP, Chapter 7
[3] PGE IRP, Appendix B pp. 366
[4] See PGE's response to staff data request 028

was not subject to the same reliability standards as the rest of the portfolios.

This modeling approach to satisfying the Order's requirement is unsatisfying. PGE's justification for this market limitation lacks rigor[5] and the Coalition questions whether applying these market limitations consistently across all modeling runs adequately complies with this requirement. These arbitrary limitations do not adequately test the benefits relying on market purchases might provide PGE's system, especially over the short-term horizon.

In response to staff data request 036, PGE observes, "the opportunity to interact with the market will tend to reduce the variable cost of mitigating flexibility challenges on the system." Despite this observed effect, PGE states that they do not intend to rely on the market to supply flexibility. The Coalition believes that this might be shortsighted. Relying for a short time frame on market purchases could provide a least cost, least risk strategy to avoid long-term investment in large, single resources that expose the Company to increased risk of fuel price volatility and stranded costs associated with fossil fuel generation.

Energy Efficiency
The E3 study from PGE's 2013 IRP demonstrated the potential for future, unrealized advancements in energy efficiency to dramatically reduce greenhouse gas emissions and portfolio energy needs[6]. PGE's portfolio modeling results from the current draft IRP also indicate that higher levels of energy efficiency reduce RPS compliance and generic capacity needs[7]. In this way, energy efficiency reduces both cost and risk.

In our comments on the 2013 IRP we observed, "*Demand-side resources have such an outsized effect on future needs, it is important to constantly improve the forecasts used to determine the availability of energy efficiency*.[8]" Unfortunately, PGE's attempt in this IRP to test the value of higher levels of energy efficiency on portfolio performance are unsuccessful because cost projections associated with the higher "above cost-effective cost" level are based on current know conditions and fail to adequately take into account historical trends in technology development and cost reduction. While the Coalition appreciates PGE's attempts to model higher levels of energy efficiency, the prices they utilize in the cost curves make this analysis virtually useless.

Energy efficiency curves beyond the 3-5 year timeframe historically underestimate technology development and price reduction of energy efficiency measures[9]. More work is needed to ensure that IRP resource planning approaches used by PGE are adequately representing the future potential of energy efficiency resources to reduce cost and risk.

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[5] See 2016 IRP and PGE response to staff data request 028
[6] PGE 2013 IRP, Appendix F
[7] Comparison of Portfolio detail for Portfolio 3 – Efficient Capacity 2021 and Portfolio 11: Efficient Capacity 2021 + High EE, PGE draft IRP, Appendix O pages 810 and 826.
[8] NW Energy Coalition Final Comments, PGE IRP 2013, Docket LC 56
[9] See The Pace of Progress, NW Energy Coalition, 2015, http://www.nwenergy.org/data/Emerging-Tech.pdf

Better methodologies to predict the future supply curves for energy efficiency are needed.

Additionally, better approaches to modeling energy efficiency's potential contributions to cost and risk are also needed. Staff recognizes the deficiencies in the treatment of energy efficiency modeling and attempts to obtain more insights in its data request 001, part v. where it asks PGE to model energy efficiency up to a different cost threshold. PGE's response sheds some additional light on the question, but is entirely insufficient to the overall question of how much future energy efficiency will be at a price point sufficient to contribute to a least cost/least risk portfolio over the planning horizon. One potential action that could be taken to address this question in this IRP cycle is for PGE to undertake a "trigger point" analysis, which would provide a price point up to which the future acquisition of energy efficiency provides both cost and risk benefits.

Unfortunately, it is not possible for the Coalition to undertake more detailed analysis of energy efficiency potential to meet PGE's future need at this time because PGE has not provided the underlying methodology and data behind its energy efficiency supply curves. In fact, PGE's responses to Sierra Club data requests 022 and 025 requesting underlying energy efficiency data state that PGE does not have the information because the Energy Trust of Oregon (ETO) compiled it. The Coalition finds it curious that PGE does not have access to the underlying analysis used by ETO, because this implies that the IRP team did not review and assess the underlying analysis used by PGE. Other studies done by third parties to inform the IRP were made available to other parties to review, and energy efficiency should be held to this same standard of open review. We encourage PGE to release this information in response to these data requests. And in the future we encourage PGE to publish ETO's underlying conservation potential assessment in conjunction with the IRP.

One additional concern regarding energy efficiency is an ongoing issue that we raised in our 2013 IRP comments concerning large customer acquisition barriers currently in place at the ETO.[10] In future years, Energy Trust may not be able to acquire all cost effective conservation from large industrial customers due to the spending limit imposed by Senate Bill 838 (SB 838) for customers with load greater than one average megawatt.

This is a very concerning issue; failing to acquire the least cost resource is not in the best interests of customers. Additionally, we believe it is contrary to the Oregon state policy to acquire all cost effective conservation. Despite attempts to resolve this issue, it remains unsolved. We urge the Commission to weigh in strongly on this issue and encourage PGE to solve the problem before the Company is unable to acquire cost effective energy efficiency.

Demand Response

The Coalition complements the Company on its thorough overview of demand response (DR) potential in the IRP. As PGE and the Northwest region shift attention in a major way to resource adequacy, capacity and flexibility, DR offers a range of resource and

[10] NW Energy Coalition Final Comments, PGE 2013 IRP, LC 56

program options that can provide help manage the dynamic grid with lower cost, lower risk and lower emissions than would be the case with new conventional resources.

Deploying DR to scale in PGE's territory and the Northwest will take considerable effort and require a major programmatic effort similar to the scale-up of energy efficiency starting in the 1980s. Long and substantial experience with DR in other regions provides an important base to work from.[11]

PGE has steadily advanced developmental work for DR over the last several years, as indicated in the IRP (detailed in Appendix I), in the annual Smart Grid reports to the Commission (Docket No. UM 1657), and in the initial array of the Company's "firm" and "nonfirm" DR pilot programs. Furthermore, the consultant report by the Brattle Group provides a comprehensive assessment of DR potential.[12]

PGE proposes to acquire 69-77 MW of new DR resources under the Action Plan through 2021. NWEC supports that as a first step but believes it is very important to stretch well beyond that. Unfortunately, PGE did not include scenarios or other analysis accelerating demand response acquisition opportunities contrary to the Commission's requirements in Order #14-415 in PGE's 2013 IPR (pp. 5-6).

PGE should maximize its effort to acquire DR from this point forward, so as to reduce the need for long-term, risky investments in large, new gas generation to meet resource adequacy, coincident system peak and flexibility needs. The 69-77 MW range should be seen as a low floor, and reassessment of potential in promising DR segments should commence as soon as possible so that this target can be pushed significantly upward.

DR resource costs may well be above a benchmark level for system valuation at this time, but concerted effort can bring the costs rapidly down for the most effective DR options. Financial drivers for rapid acceleration of DR by PGE are now in place, especially with the capacity gap in 2021 resulting from Boardman shutdown.

In its Seasonal Capacity Products analysis (IRP, Section 5.1.4.1), PGE uses a provisional estimate of the average cost of an annual capacity resource as $100/kw-yr. While this value needs further refinement, and winter and summer seasonal capacity resource cost should be separately assessed, this provides a useful starting point for valuation of fully developed DR resources.

In one case this level of assessment has already been accomplished. The thorough review of battery storage in Section 8.5 is one of the best parts of the IRP. This includes Figure 8.6, showing that the net cost impact in 2021 of a 50 MW, 2-hr battery is somewhat above that of a 25 MW frame CT. But we also have a widely available and far less

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[11] BPA Distributed Energy Resource Benchmarking Report, Oct. 2016, https://www.bpa.gov/EE/Technology/demand-response/Documents/2016_DERBenchmarkReport.pdf.

[12] Demand Response Market Research: Portland General Electric, 2016 to 2035, Brattle Group, Jan. 2016.

expensive storage-based DR option in the PGE service territory: electric water heaters (EWH). DR options include both conventional direct load control (DLC), practiced for decades in the eastern US and having a mature market with standard unit controls, grid dispatch and rate mechanisms, and more flexible "grid integrated water heaters" (GIWH) providing storage as well as load control functions. In addition, there is strong interest in the region, especially via the Northwest Energy Efficiency Alliance, in developing grid-integrated heat pump water heaters.

By very rough estimate, the DR resource from DLC or fully dispatchable EWH may cost as little as 20% of battery storage. But we do not yet have a refined estimate of the total economic and achievable potential for this DR resource in PGE territory. Developing a full-scale water heater DR program will require considerable effort, and PGE has begun this work. An important step is the joint initiative PGE is undertaking with the Bonneville Power Administration to conduct a small pilot program testing a new water heater plug-in device conforming to the ANSI/CTA-2045 modular communications interface standard.

However, PGE should dramatically accelerate its activity in building up a water heater DR resource. While retrofitting EWH is probably not cost-effective even for a mature program, the overall market potential is very large. Given that the average in service life for a water heater is 10-15 years, and that plumbing suppliers basically determine product specifications while meeting customer water demand and unit cost goals, the EWH DR market will actually be more amenable to scale-up than other end user focused programs. Our very simple estimate is that 10 MW per year or more of new EWH DR may be available from new and replacement installations in the PGE service territory. Given the high value of DLC or GIWH dispatch, program incentives to customers and to the EWH and HPWH industry can be very generous, and we anticipate fast market uptake once the right program elements and supply chain alignments have been identified.

It is important to start fast-tracking efforts and to apply early learning from programs like the BPA CTA-2045 test to planning for EWH DR program efforts over the next several years. Now is the time to switch from a very slow, methodical approach to DR development, especially for water heater DR resources, to one that remains methodical, evidence-based and closely tuned to customer acceptance while setting much higher adoption rates and resource targets.

Solar PV Cost Projections

The Coalition appreciates the in-depth work by PGE and its consultants on present and future projected costs for all forms of generation. However, we question the validity of the underlying assumptions for innovation-driven technologies. It is crucially important for analysis and selection of preferred portfolios that a plausible range of future costs be adopted for available resources. We do not believe this is the case for solar PV in the IRP.

B&V provides capital cost reduction percentages by year for numerous technologies through 2034, while DNV GL reports annual offshore and onshore wind and 5-year interval solar PV projections through 2040.[13] The results are disappointing in terms of both historical context, the current market environment for these resources, and likely future cost trajectories. In sum, the consultant projections greatly understate the likelihood of future cost declines for solar PV.

While trend analysis is acceptable for typical conventional generation, the trend method only works well for mature technologies. This is because emerging, innovation-driven technologies are subject to rapid cost declines during early phases of market expansion. This phenomenon has been widely studied and the method is generally referred to as "experience curve" (sometimes "learning curve") analysis. For background we provide a paper the Coalition prepared for the Western Electricity Coordinating Council in 2012 (Attachment 1).[14] Since that time, experience curve analysis for solar PV in particular (but also for wind, battery and other fast moving innovation-driven technologies) has rapidly emerged.

Furthermore, intensive and statistically rigorous assessments of the experience curve methodology have been conducted, particularly at Santa Fe Institute.[15] The assessments cover a wide range of industries, technologies and historical cost data. The conclusion is simple: properly applied, experience curve assessment is robust for long-term projection of technology costs. Integrated resource planning over a 20-year or longer horizon is exactly the right context in which to use the experience curve method.

Experience curve analysis relates aggregate market size to cost. Typically, an experience curve is derived as a fixed cost decrease ("learning rate") per doubling of aggregate market size. For example, starting in 1980 there have been many studies of solar PV module costs, and they tightly converge on a learning rate of 20%. Thus, experience curve analysis suggests that as the solar PV market at the national level goes from 0.5% to 1% of total electricity generation, module costs will decline about 20%, another 20% as PV saturation goes to 2%, and so forth.

Of course, there are additional costs for providing solar PV, including support structures, electrical connections, inverters, labor, marketing, overhead and margin. These "other" costs are important to understand because they are now a large part of total cost, perhaps 70%. In addition, while PV modules are in a global market these costs are more localized, and fewer in-depth studies have been done. Nonetheless, as a conservatism, the Coalition adopts a rule-of-thumb from several studies showing that the "other cost" learning rate is 15%.

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[13] Table C-1 of the Black & Veatch report (p. 751 of the draft report) and Table C-1 of the DNV GL report (p. 787).

[14] Experience Curves and Solar PV, 2012, submission by NW Energy Coalition to Western Electricity Coordinating Council.

[15] Nagy, B., Farmer, J.D., Trancik, J.E., Gonzales, J.P., 2011, Superexponential long-term trends in information technology. Technol. Forecast. Social Change 78 (8), 1356–1364; J, Doyne Farmer and Francois Lafond, How predictable is technological progress?, Research Policy 45, 647–665.

The Coalition has created a “simple solar model” (SSM) spreadsheet that provides an easy to use exploratory tool for solar PV experience curve analysis. We present below a side-by-side comparison of the B&V, DNV GL and SSM results. For our SSM results, we choose a doubling period of five years (DPY 5). If current solar PV is 0.5% of total generation, that would mean doubling to 1%, again to 2%, then 4%, and finally 8% in 2035. This is not a prediction of when each doubling will occur, but rather a way to provide a long-term projection.

This is far more conservative than we anticipate solar PV costs will evolve; it is more likely that four doublings will occur within 10-12 years; the current doubling rate is between 2 and 2.5 years, and PV costs have been falling accordingly. We also provide our DPY 4 analysis, indicating five doublings between now and 2035. The DPY 4 and DPY 5 values provide a useful range for comparison to the conventional trend analysis, as shown in the table and chart below.

We show that experience curve analysis projects that solar PV costs will decline much faster than in the traditional trend analysis. We anticipate cost reductions of one-third (like DNV GL’s value of 0.68 in 2035) will occur no later than 2025 (our DPY 4 value of 0.64). And our analysis indicates that solar PV will be 50-60% lower than at present in 2035, not 22% (B&V) or 32% (DNV GL).

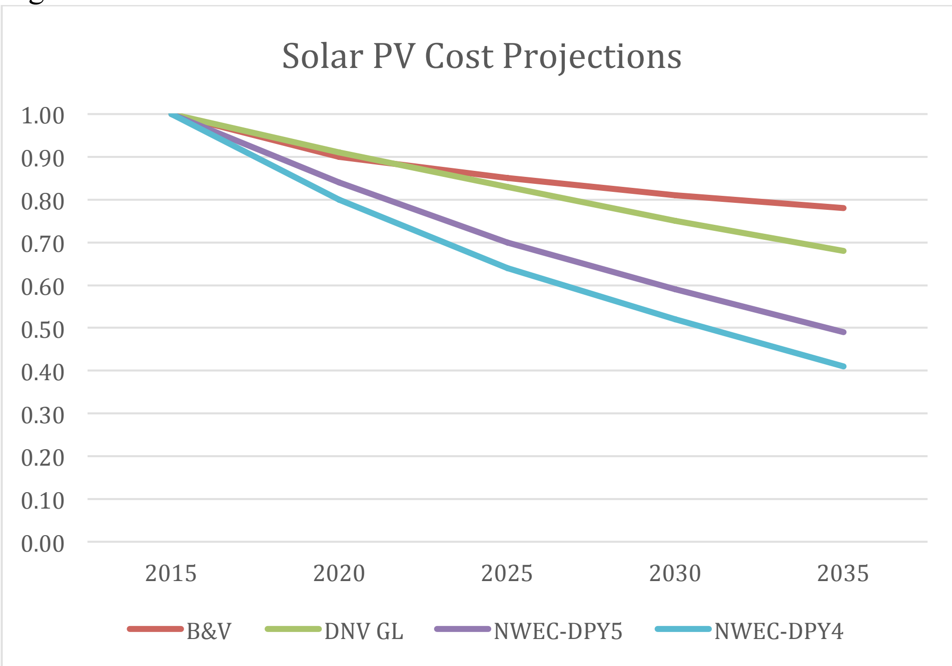
Because this analysis is only of capital cost and not life cycle cost of energy (LCOE), it does not allow for direct cross-resource comparisons. However, we observe that wind LCOE is already below that of natural gas generation, and solar is approaching parity. The continued, dramatic decline in solar PV costs foretells a massive opportunity for PGE to move quickly on securing the solar resource quickly over the next 5-10 years rather than deferring it and allowing new gas to displace it.

We suggest that PGE adopt a dual approach of assessing solar PV and other innovation-driven technologies (including but not limited to wind and various forms of storage) with both trend analysis and experience curve analysis, and run additional studies to assess the potential impact on the resource mix for preferred portfolios from cost declines projected by the experience curve method.

Table 1: Solar PV Cost Projections

Year	B&V	DNV GL	NWEC-DPY5	NWEC-DPY4
2015	1.00	1.00	1.00	1.00
2020	0.90	0.91	0.84	0.80
2025	0.85	0.83	0.70	0.64
2030	0.81	0.75	0.59	0.52
2035	0.78	0.68	0.49	0.41

Figure 1



Failure to Consider Least Cost Portfolio

The Company failed to advance the least cost portfolio, "Diverse Wind 2021" because PGE did not fully account for transmission costs in the portfolio development. "Diverse Wind 2021" (also occasionally referred to as "Diverse Wind 2018")—which includes wind built in Montana—has a lower cost than the preferred plan by an average of over ***$450 million dollars*** across all futures analyzed, yet was dismissed from consideration prior to the scoring metric process. This rationale falls flat for the Coalition because this scenario clearly shows a tremendous benefit to acquiring diverse wind on PGE's system.

PGE has asserted that the characteristics of Montana wind were chosen for modeling purposes, but acknowledged that there is a potential for wind that does not perfectly match the characteristics of "Gorge wind" nor "Montana wind" to bid into the system. Seen as a proxy for wind with a higher capacity factor than Gorge wind, the full vetting of this portfolio seems particularly important. Additionally, given the tremendous economic value that Montana wind represents to PGE's system, perhaps rather than discarding this portfolio, PGE should put more time and resources into examining the associated transmission questions (see related discussion regarding transmission below). We recommend that PGE run the scoring metric analysis for this portfolio and present the results in this IRP docket.

Oregon State Greenhouse Gas Reduction Goals

IRP Guideline 8d requires utilities to model at least one portfolio that achieves the greenhouse gas reduction goals adopted by the Oregon State Legislature in 2007. None of

PGE's actionable portfolios achieved these goals in 2050.[16] In fact, in the IRP modeling scenarios, several portfolios get close to achieving the intermediate 2035 goal, but at that time greenhouse gas emissions under all modeled portfolios begin to increase over the next 10 years, resulting in a large gap toward meeting the 2050 state goal.[17]

To comply with the guideline 8d, PGE created an additional portfolio "2050 Oregon GHG Goal" using Efficient Capacity 2021 as a base and "effectively displacing market emissions" with renewable resources in the 2035 – 2050 timeframe[18]. It is unclear whether PGE actually only replaces market purchases, because the presentation of the portfolio in Chapter 12 is lacking considerable detail and Table 12-10 describing resource additions is confusing. It appears, however, that resource additions described for the 2050 Oregon GHG Goal portfolio in 2040 (438 MWa), exceed the market position in 2040 for the Efficient Capacity 2021 portfolio presented in Appendix O Figure O-6 (300 MWa). Projections for market position are not given past 2040 for the Efficient Capacity 2021 portfolio so it is impossible to tell whether the apparent discrepancies continue to increase or not. However, PGE does tell us in Chapter 12 that the renewable resources included in the 2050 Oregon GHG Goal portfolio would represent nearly 80 percent of retail load in 2050[19]. It seems possible that this level of renewable resources would potentially require early retirement of some natural gas resources. These findings certainly demonstrates the value of non-carbon emitting resources toward meeting the State's GHG goals, as well as demonstrating the risk of overreliance on natural gas toward this end.

III. Early Action Renewables

The Coalition supports PGE's analysis indicating early procurement of RPS resources is a least cost, least risk strategy. Several portfolios were developed specifically to test timing of resource procurement for RPS compliance[20]. The relative NPVRR of the portfolio with early renewable acquisition in time to capture the full value of federal production tax credits (PTC) consistently ranked as least cost relative to portfolios that deferred resource acquisition until 2020, 2021 or 2025. Additionally, portfolios developed to test deferred RPS procurement through utilization of the REC bank or utilization of unbundled RECs illustrate that early procurement of resources is consistently the least cost strategy[21].

The passage of HB 1547 last year that increased the Oregon's renewable portfolio standard to 50% by 2040 raised some concerns for the Coalition regarding the potential for this policy to encourage building resources that were not needed to meet utility resource needs. In this case, PGE is not merely obtaining resources to meet RPS compliance, but faces significant energy and capacity needs as a result of retiring

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[16] PGE draft IRP, Chapter 12 Modeling Results pg. 324.
[17] See PGE IRP, Figure 12-8, Chapter 12, pp. 324
[18]Ibid, pg 234-5
[19] Ibid, pg. 235
[20] PGE Draft IRP 2016, Chapter 12 Modeling Results and Appendix L, section L.2.1
[21] Ibid, Appendix L. section L.2.2

generation. It is important to note that in the early procurement of renewables in this analysis, resources are acquired for RPS compliance, but additionally serve to meet the Company's near term resource needs. Without the action plan's proposed renewable resource procurement in 2018, PGE's need for generic capacity would increase. The Coalition supports the IRP conclusion that the Company should procure at least 175 aMW of renewable resources by 2018, in order to capitalize on the full PTC value.

III. Transmission

The IRP includes a considerable amount of useful detail about PGE's transmission system and its contractual rights on other systems, particularly the Bonneville Power Administration (BPA). Yet, the overall treatment of transmission in the IRP leaves many questions, including perhaps most significantly, PGE's existing transmission rights and the value new transmission projects could bring to PGE's system by facilitating connections to low-cost renewable energy.

While interchange with other systems has always been important for PGE to gain access to its own and other resources and provide better and more reliable service to customers, recent developments highlight the increasingly important role that transmission must play in order for PGE to move toward a more reliable, clean and affordable system.

Energy Imbalance Market

The Coalition applauds the impending activation of PGE as a participant in the California ISO Energy Imbalance Market in the fall of 2017. This will provide important flexibility, improve system dispatch, and reduce the use of expensive natural gas reserves at the margin to meet intra-hour variability of both supply and demand.

While it was never anticipated decades ago when PGE purchased a share of the California-Oregon Intertie, this highlights the importance of available transmission capacity to use our increasingly diverse resource mix, and combine efforts across Balancing Area Authorities to make more efficient use of the existing grid.
The recent adoption by Peak Reliability, going into effect on April 1, 2017, of a substantially reformed System Operating Limit (SOL) methodology and other flexibility initiatives at Peak to move from an overly conservative static approach to more dynamic grid management, may help increase the capacity of the existing grid and provide more usable capacity for PGE.

Access to New Renewable Resources: Montana and Eastern Oregon

The IRP notes (p. 249) that PGE has surplus available transmission capacity coming from the Mid-C area. However, further clarification on the quantity available is needed. Fig. 9-2 notes, "The values represent PGE's transmission position relative to generation for each location." It is not clear whether the values in the chart reflect only the generation current used across each path. It would also help to have a sense of whether the constraints across the North of John Day, West of John Day and Cross-Cascade South cut-planes in the BPA system can be alleviated and create more usable ATC for PGE.

With the sense that a significant amount of potential ATC is available between Mid-C and the PGE system, full attention should be directed by PGE and the Commission to the potential for wheeling new Montana wind, with a view to making arrangements that will move BPA toward reactivating its effort to upgrade the Montana-to-Washington path.

Likewise, existing transmission capacity between Boardman and the PGE system should not be locked in only for new natural gas at the Carty site once the coal plant is retired. To the extent that new gas can be minimized at Carty or sited within the PGE system itself, the newly available ATC will have very high value as a conduit for a radial collector system for new solar in eastern Oregon and other clean resources. It would make no sense to dedicate existing ATC to gas and then either not develop new renewables, wheel them from other systems at higher resource and transmission cost, or require investment in new transmission with years of development time, difficult siting requirements and high cost.

Regional Transmission Cooperation

The Coalition appreciates the discussion in Section 9.1.3 of regional transmission assessment. PGE's transmission system and those of adjacent areas could once be planned somewhat in isolation, but that is definitely no longer the case. We believe a more comprehensive and collaborative approach is now needed.

There are two capable transmission planning bodies in the region: Northern Tier Transmission Group (including PGE, PacifiCorp and others, mostly investor owned utilities) and ColumbiaGrid (including BPA, Puget Sound Energy, Avista and publicly owned utilities in Washington). There are also numerous transmission planning processes across the area. However, there is little cohesion across these efforts, and consequently issues such as the South of Allston constraint have grown for many years until they have reached an urgent level.

The South of Allston path is operated by BPA but co-owned with PGE and Pacific Power and is the main north-south channel for generation coming into the Portland area. There are both operational and long-term reliability compliance issues with the path, caused by load growth in the Portland area boosting summer peak demand, as well as flows to California during some late summer afternoons pulling generation through Portland. These events increase flows from generation to the north as far as British Columbia, but there is a bottleneck across the South of Allston cutplane. In a worst-case situation, loss of load could occur in the Portland area on a hot summer afternoon.

Both BPA and PGE are considering new transmission builds that would alleviate the path constraint, as well as various operational and non-transmission alternatives. While we understand that the path owners have conducted some informal assessment work over the last year, it is the time to evolve toward a more open, comprehensive and collaborative transmission assessment process in this area, and soon, across the entire Northwest.

The South of Allston path owners appear to be moving in a direction that will result in a more balanced, effective, lower cost and more flexible approach than constructing the

BPA I-5 Corridor Reinforcement Project, but the process has not been transparent and risks losing insights from subject matter experts on demand response and other relevant topics, as well as general stakeholder involvement.

Finally, it is important to recognize, as PGE already does, that the goal of transmission planning is not to build more transmission, but to optimize the existing grid. When changes in loads and resources occur, all options must be fully assessed and weighed carefully, including operational changes, nonwires alternatives (demand response, etc.), coordination with adjacent transmission systems, market-based measures such as the Energy Imbalance Market and perhaps an independent system operator, as well as transmission expansion.

The Coalition recommends that PGE to reflect the need for stronger, more coherent and more open and transparent regional transmission cooperative planning in the IRP.

IV. Scoring Metrics and Risk Evaluation

Probabilistic analysis
PGE's risk analysis subjects predetermined portfolios to a series of different futures with a variety of conditions (gas prices, carbon prices, etc.). The Company fails to assign probabilities to the different futures, which means in PGE's risk analysis, each future is equally weighted in terms of how likely it is to occur. A preferred approach is to use a probability analysis, which assigns each variable a probability of actually occurring. PGE's approach of treating all futures as equally likely, combined with the deficiencies in their scoring metrics described below, has the impact of giving too much weight to unlikely futures.

Scoring metrics
For its risk analysis, PGE developed a set of scoring metrics to arrive at a portfolio score out of 100 possible points for a subset of the portfolios modeled. Cost made up 50% of the score, with three risk metrics, "severity", "variability" and "durability" assigned equal weights of 16.67% each to make up the additional 50%. The severity metric measures the cost of the three most expensive futures for each portfolio. Variability measures the range of costs that fall above the reference case cost, with the most expensive cases weighted more heavily. Durability is a measure of the frequency with which each portfolio is ranked among the top-third lowest cost or bottom third, highest cost of all portfolios for a given future. These particular metrics and the approach to portfolio scoring are unique to PGE – we are unaware of other utilities that use this same approach.

The approach leads to three top performing portfolios that score within a couple of points of each other. A slight change in the weighting of one or more metrics could shift any of these three portfolios into the top position. Furthermore, PGE has not justified, nor vetted with stakeholders, the relative weighting of the scoring metrics.

The Commission's IRP Guideline 1c states that utilities should rely on present value revenue requirements (PVRR) as the key metric of cost, and that utilities should measure portfolio risk by using at least two separate measures which address the variability of costs and the severity of high-cost outcomes. There is no mention of durability in the guidelines. Indeed, the Coalition maintains that the severity metric and the durability metric measure almost the same elements and are consequently duplicative and giving additional weight to severity, under emphasizing variability. This has the effect of overstating cost results, even if it is a single high cost result that is driving the calculations, and under-representing low cost results. The precise method of calculating the durability metric is also flawed because it obscures portfolios that end up with a preponderance of mid- level costs.

The Company's approach to the scoring metrics does not provide useful information about the risk of various portfolios under future conditions. For this IRP, at a minimum, we recommend that the Company remove the "durability" metric from its calculations. For future IRP's we recommend the Company develop a new methodology for portfolio evaluation in conjunctions with stakeholders.

Natural gas prices

Projections of future gas prices are crucial to many aspects of the IRP, particularly the anticipated cost of new gas resources and the dispatch patterns in the AURORAxmp model. Since natural gas decontrol began three decades ago, the structure of the natural gas industry, supply and demand patterns, and spot market and forward prices have gone through several significantly different periods.[22]

The Coalition initially drafted a lengthy analysis of natural gas prices to include in these comments, intended to make the argument that the prices the Company is using for the base and high natural gas cases are generally too low. However, we decided not to include these comments because the real issue is that natural gas prices are historically highly unpredictable. Our higher projections have no more certainty of being right than the assumptions PGE uses in the IRP. PGE itself recognizes the long-term risks associated with natural gas prices through its inclusion of Appendix Q, *Regulated Utilities Investing in Natural Gas Reserves and Production: Recommendations on How to Avoid the Risks and Capture the Big Prize* and in its initial filing in UE 306[23].

Natural gas price volatility is especially relevant considering this IRP Action Plan, which contemplates a preferred portfolio with a dramatic increase in new gas generation based on a reference case using trend projections that predict flat gas prices for the foreseeable future. Perhaps in this context, the idea of addressing natural gas price risk simply through the use of forward curves to set expectations for forecasted natural gas prices is outdated and insufficient. Additionally, nothing in PGE's scoring metrics or methodology is geared toward specifically addressing the risk of natural gas price volatility.

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[22] An authoritative and readable account with substantial historical data is found in this publication: Michelle Michot Foss, The Outlook for U.S. Gas Prices in 2020, Oxford Institute for Energy Studies, NG 58, Nov. 2011, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/12/NG_58.pdf.

[23] http://edocs.puc.state.or.us/efdocs/HAA/haa151749.pdf

The Coalition recommends that in issuing an order on the IRP, the Commission consider the lack of sufficient consideration to natural gas price risk in the IRP analysis. Specifically, the Commission could consider conditions of acknowledgement that mitigate for this risk, and order the Company to work with stakeholders to improve its methods for addressing this type of risk in future IRPs.

V. Action Plan

The Company presents an action plan that primarily hinges on resource decisions being made in an all source RFP. The Company states that it will consider procurement of the most cost effective resources to meet the identified capacity and energy needs. However, the Coalition is concerned that the overreliance on proxy resources across all portfolios in the IPR and the failure to adequately assess the cost and risk of other resource choices in meeting these needs through the IRP modeling will make it extremely difficult to effectively structure an RFP.

The Coalition has concerns about a single all source RFP adequately evaluating resources of different resource types, duration and size. How will the Company be able to assign RFP scoring criteria that adequately represent resource contributions when they have not modeled many of the resource choices that may bid into an RFP? How will the RFP be able to adequately evaluate groupings of smaller resources against one large resource? How will an RFP adequately evaluate resources of differing duration – 5-year contracts vs. a 30-year investment? Additionally, some resources lend themselves better to the RFP process, while other resources, such as hydropower might be better procured through bilateral negotiations.

Furthermore, given the close scoring of the top 3 portfolios with dramatically different resource selections it seems most prudent to delay decisions related to significant, long-term capital intensive investments, particularly those that rely on natural gas due to historical natural gas price variability and its contributions to greenhouse gas emissions.

VI. Recommendations

<u>*Resource Acquisition/Action Items*</u>

1. Acknowledge early action acquisition of renewables to ensure the PGE is able to acquire resources with full PTC value. Consider a dedicated renewables RFP to accomplish this action.
2. Require PGE immediately undertake additional transmission analysis to inform near term resource selection.
3. Consider developing conditions for the final IRP order that address the following with regard to RPF and other going forward resource procurement actions:
    a. Potential issuance of two or more RFP's that seek short and long term resources or consider other means to ensure adequate evaluations of different length resources in a single RFP.
    b. Encourage bilateral negotiations rather than RFP for certain resources –

particularly hydropower.

c. Re-run some scenarios and produce additional analysis based on RFP bids prior to final resource selection and procurement.

4. Ensure that demand side resources have an opportunity to compete in the final RFP process.

IRP Update/Next IRP

1. Ensure that PGE initiate a stakeholder process to improve long-term energy efficiency supply curve development methodology.
2. Ensure that PGE make detailed information regarding its energy efficiency supply curve development and analysis available to stakeholders concurrent or prior to IRP filing.
3. Strongly encourage PGE to solve the large customer energy efficiency acquisition barriers.
4. Request that PGE adopt a dual approach of assessing solar PV and other innovation-driven technologies (including but not limited to wind and various forms of storage) with both trend analysis and experience curve analysis, and run additional studies to assess the potential impact on the resource mix for preferred portfolios from cost declines projected by the experience curve method.
5. Risk analysis/Scoring metrics – review and improve methodology and approach with stakeholders.
6. Improve the methodology for representing natural gas fuel price risk in future IPRs.

VII. Conclusion

Several extremely close ranking portfolios with dramatically different future resource selections and under representation of non-fossil resource options in the portfolio analysis, combined with deficiencies in risk evaluation and scoring metrics all contribute to a conclusion that the Company's preferred portfolio, which relies heavily on investments in large fossil fuel resources, is not the logical least cost/least risk conclusion. The extremely close results in both cost and risk for several portfolios argues for an approach that shuns large investments in long-term, natural gas resources in favor of short term contracts or market purchases until such time as investment choices can be modeled with more conclusive results.

PGE's IRP Action Plan puts a lot of pressure on the RFP process to select the best combination of resources to meet system needs. The foundation provided by this IRP analysis is insufficient to guide these actions, and more consideration about the best path forward is warranted. The Coalition supports the Action Plan item for early acquisition of approximately 175 aMW of renewables, but concludes that more thought is needed around pursuing short-term options that rely on DSM and market rather than pursuing 30+ year commitments to large fossil fueled generation.

Respectfully submitted this 24th day of January 2017,

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Wendy Gerlitz Policy Director	Fred Heutte Senior Policy Associate

Experience Curves and Solar PV

Fred Heutte, Senior Policy Associate
NW Energy Coalition
September 3, 2012

Estimation of current and projected future resource costs is a core part of the Western Electricity Coordinating Council's transmission planning for the 10-year Common Case based plan, and even more for the 20-year scenario based plan, both part of the Regional Transmission Expansion Planning (RTEP) project.

The effort to identify current costs is complex and, not surprisingly, the data is neither consistent nor complete. Further, the effort to assess future projected cost is subject to numerous analytical choices.

Both current and future projected costs should be assessed consistently, using the best data available, with transparency on assumptions, methods and the selection of parameters, and balancing all the contributing factors to select the best available estimates given the range of uncertainties involved. While single point estimates may be needed for modeling purposes, it is important to think both present and future resources costs as being ranges rather than fixed values.

It is evident that the question of future solar PV resource costs is a Big Question for the RTEP planning process. While use in the western grid is a very small percentage of all resources at present, there is a strong sense that once solar PV reaches "grid parity"[1] it will rapidly become a much more important part of the mix. Beyond that point, as economics favor rapid uptake, end-use oriented PV will substantially decrease demand, and utility-scale PV will increase supply. And those changes in both sides of the market, along with the unique diurnal and seasonal shape of the solar resource, will significantly affect future grid operations and the need for transmission expansion.

Consequently, the future estimated cost projection for solar PV has been a point of considerable discussion in the RTEP process.

As the development of RTEP modeling has taken shape, there is agreement that the use of a "learning curve" (or "experience curve") method is appropriate for estimating future resource costs.

[1] Recent commentary suggests treating the "grid parity" concept with considerable restraint due to the many and often unspecified assumptions about the context, for example, whether "parity" is based on retail or wholesale power costs, the location, and whether the comparison is based on average or peak pricing (BNEF 2012a: 11). However, "grid parity" remains useful shorthand for the idea that fossil resource prices are generally increasing, and renewable energy is generally decreasing, and at some point the historical advantage fossil based electricity has had will reverse, with significant consequences for future resource mix and transmission deployment.

However, it has been proposed that the experience curve for solar PV should be dramatically changed "downward" going forward (i.e., significantly less of a cost decrease per unit of marginal production).

This short paper will review the background of the experience curve method and the application of that approach to solar PV. We conclude:

(1) The strong preponderance of evidence suggests staying with the consensus experience curve estimate – a Learning Rate of 20% for solar PV modules and 17% for balance-of-system, going forward through the 20-year planning horizon.

(2) Differing levels of future solar PV market expansion should be captured in the different RTEP 20-year scenarios. While the experience curve should be kept constant, there will be different doubling periods for solar PV under differing policy and market conditions.

1. Comparative Analysis of Future Technology Market Penetration and Cost

Numerous approaches have been tried over time to project changes in market penetration, price and time for technology-oriented products (Junginger 2006). Among them are:

- cost per cumulative production
  - learning curves (per firm)
  - experience curves (per industry)
- cost per annum
- cost per annual production
- expert elicitation ("Delphi process")
- engineering models

Observation over many years and new formal analysis suggests that experience curves have the best track record for projecting future costs. A recent paper sponsored by the Santa Fe Institute (Nagy et al. 2012) summarizes a meta-evaluation of estimation methods including cost per cumulative production ("Wright's Law"), cost per annum ("Moore's Law"), cost per rate of annual production ("Goddard's Law"); time-lagged variants of the single factor approaches; and hybrid or multifactor estimators combining the single factor approaches (based on work by Nordhaus and Sinclair, Klepper, and Cohen).

Forecast skill for each of the methods was assessed with a hindcasting approach across 62 technologies in four categories (chemical, hardware, energy and other), with time series ranging from 11 to 39 years.

The analysis concludes that the traditional experience curve approach (Wright) performs quite well across technologies and different time scales, and is significantly better overall than the other approaches, although Moore is very close over shorter time ranges. The robustness of the results for the experience curve approach is striking.

2. Learning Curves and Experience Curves

In 1936, Theodore Wright presented observations of a regularity in cost reduction as planes were manufactured at Boeing. Further studies in industrial manufacturing found similar "learning effects" and became known as the "learning curve," usually expressed as a constant cost reduction per doubling in cumulative production.

The effect is usually expressed as the "learning rate" (LR) or percentage reduction per doubling in cumulative production, or the "progress ratio" (PR), which is reduction relative to the previous period. These are identities; a 20% LR is the same as 80% PR. Both LR and PR parameters continue to be used in the literature.

In the 1960s, especially with influential studies by the Boston Consulting Group, the learning curve concept was expanded from assessment of single-firm product learning curves to industry-wide assessments, and the term "experience curves" came into use. While the terms are still used somewhat interchangeably, because we are looking at global product categories it is more appropriate to use the term "experience curve" in the context of RTEP planning.

3. Characteristics of Experience Curves

Experience curves have been extensively studied and critiqued. Dozens of studies of existing experience curves and meta-analysis across products were reviewed for this paper, showing very consistent results.

Over several decades of use, experience curves have shown regularity across industries and products. When used in an appropriate context, this approach can be a powerful tool for analysis. However, several observations should be made on the range and limitations of the technique.

Observational not functional. While very regular and robust in its results, the experience curve method does not have a clear functional underpinning. Various hypotheses have been proposed for the regularity of the experience curve results as an emergent property of learning, scale economies, development stages, market structure, etc. Conceptually it seems likely all of these are factors that derive broadly from the dynamics of technology diffusion in a market-based economy. Interestingly, the Santa Fe Institute group suggests their analysis shows that scale economies are responsibly for the majority of the effect, with learning a minority but still important component (Nagy et al. 2012: 5).

Scale-free, stable and product-specific. Learning and experience curves show a scale-free but product-specific characteristic value. That is, there is no evidence that, once established, an experience curve deviates much over time throughout a product's history, including end-of-cycle. Since the last doubling, by definition, is half the ultimate market penetration, the effect may appear to be diminished but the constant cost reduction may be spread over a considerably longer time period.

Stability over life cycle, deviations over short spans. Over the typical multi-decadal life cycle of technology-oriented products, the experience curve tends to be quite stable. Overall, experience curves remain constant regardless of developmental stage. However, short-term deviations are often observed at annual or sub-decadal scale, but these appear to be driven by market, production and policy intervention factors as products move from stage to stage -- for example, from innovators to early adopters (Yeh et al. 2007).

Industry analysis generally suggests an "S-curve" approach to technology adoption over time: starting slowly, then rapid uptake, then declining use toward obsolescence (Junginger 2006).

In general, there are two main approaches to development stage analysis, production-based and market-based. Production-based analysis often uses a 6-stage model (e.g., invention, RD&D, niche market, pervasive diffusion, saturation, and senescence). The well-known market-based approach generally has a 5-stage model (innovators, early adopters, middle market, laggards, termination).

While short term changes in experience curves appear within and across developmental stages, especially the early ones, a notable feature of experience curves is regression toward an underlying characteristic Learning Rate/Progress Ratio over longer time scales.

Because of observed short-run variations, some analysts recommend a blended approach of experience curves and expert assessment, especially for shorter-run projections (Black & Veatch 2012). Nevertheless, experience curves provide significant assurance over the longer term.

4. Constraints for Experience Curve Analysis

Effective use of experience curves requires attention to several issues:

Unit of analysis. Selection of the most appropriate production unit is important. When in a "learning curve" context, usually applied to a specific product from a single firm or closely-comparable products across an industry, production counts may be sufficient. But for many products, especially energy technologies, cumulative output capacity is a more relevant measure (IPCC 2011: 366). The selection of the best parameter is still an issue, however.

Over the last several years, for example, the experience curve for wind turbines seemed to deviate well away from the historical record, as turbine prices actually increased for a couple of years. However, this was based on assessment of kW capacity rather than average output or LCOE, both of which improved relative to kW capacity based on increasing blade lengths, sweep areas and hub heights, and improved efficiency for larger turbines (NREL 2012). While the cost based on output or LCOE did deviate somewhat from the historical curve, it did not change sharply and appears to be reverting to the longer-term norm as short-term market factors (for example, rapid run-up in steel prices) work back toward the mean.

Cost comparability. It is important to take an appropriate and consistent approach to converting nominal costs to real costs to preserve comparability across time.

Currency cost normalization. For global experience curves, normalizing cost data through appropriate exchange rate conversions is a key step.

Sub-product experience curves. Observation sometimes indicates that it is appropriate to disaggregate product experience curves. For example, it has long been considered appropriate to have separate solar PV and balance of system (BOS) experience curves, and to consider utility-scale and end-user systems separately (IRENA 2012).

5. Best Uses of Experience Curves

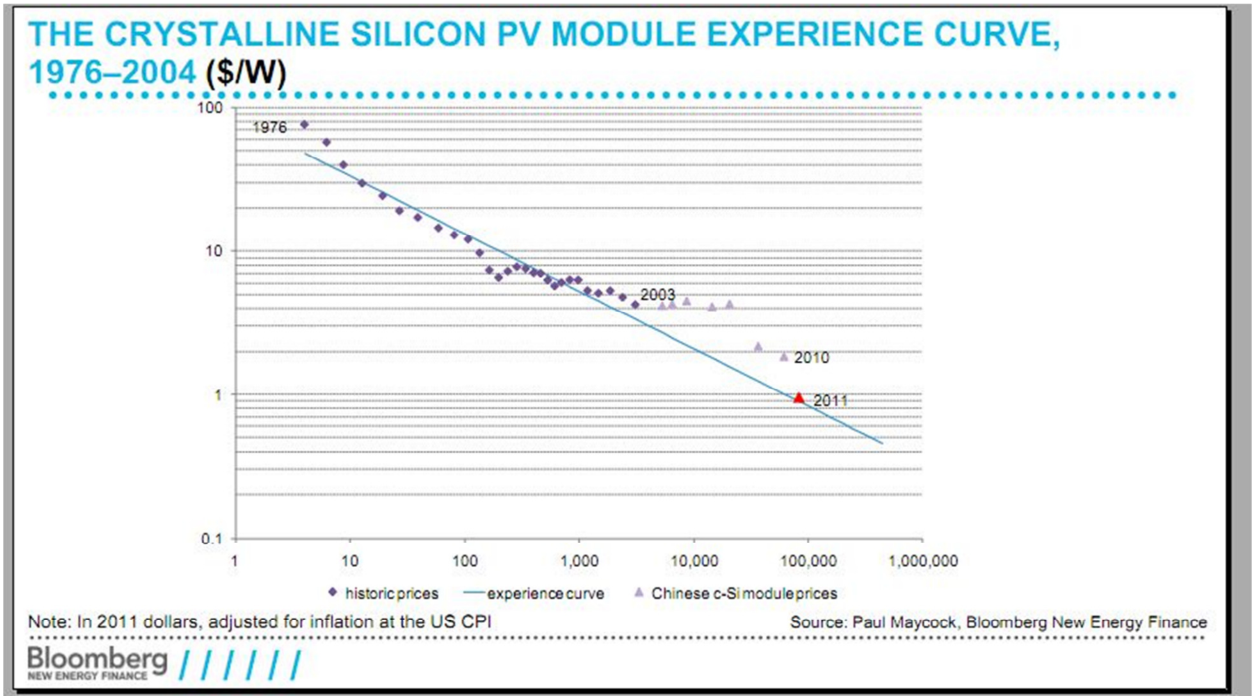
The basic characteristics of experience curves suggest that over time, cost is invariantly related to market size. This turns the standard planning perspective on its head. We usually inquire: what will the market size be assuming a given cost in some future year, using expert judgment, bottom-up engineering and economic modeling to estimate a fixed-point cost. This is the approach most suited to conventional deterministic modeling.

However, the experience curve approach flips this around. The question then is: how large will the market be for a resource in a future year, and then that tells us the cost based on cumulative production. This approach is well suited to dynamical or scenario-based modeling, including the ability to build in varying types and levels of policy interventions and market changes that characterize different scenarios. In this context, experience curves provide a useful exploratory tool.

6. Experience Curves for Solar PV

Experience curves have been an established part of public policy and industry analysis of solar PV and other renewable energy technologies for over three decades. An early study by SERI (1980) laid out a framework approach to learning and experience curves. Numerous projections and refinements using experience curves have been conducted ever since.

While values in published solar PV experience curves range somewhat, with learning rates of 10% to 30%, by far the most common long-term experience curve value for solar PV is 20% (i.e., a 20% cost reduction per doubling of cumulative output). This central tendency persists despite the use of different time periods, different geographic ranges (global or national), and differences in data treatment and analysis.



BNEF 2012b, slide 5

A typical widely-cited analysis by Strategies Unlimited indicates a PR of 80.0% +/- 0.4 (LR = 20%) for 1976-2001. More recently, Nagy et al. (2012) using two slightly different data sets, estimate PR of 81% (LR = 19%) for 1976-2002 or PR of 71% (LR = 29%) for 1977-2009, indicating some sensitivity to late-decade effects. The IPCC's global renewable energy assessment, citing numerous sources, assesses solar PV module learning rate as 20% and balance-of-system between 18% and 21% (IPCC 2012: 380).

7. Can Policy Affect Experience Curves?

Visual examination of experience curves for solar PV and other energy products indicates that policy interventions can affect experience curves temporarily. The well-known pause in PV module cost reductions of the mid-2000s is widely understood as a consequence of feed-in-tariff policies, especially in Germany and Spain. However, this was also accompanied by a dramatic market expansion, decreasing the time span for cumulative doubling. As a result of several factors, including rapid reduction of the Spanish FIT and gearing up global production capacity, module prices have fallen dramatically since 2008, pulling costs back toward the long-term experience curve.

The Santa Fe Institute study (Nagy et al. 2012) also lends credence to the idea that policy intervention either to subsidize cost reductions directly or to expand markets probably has only a temporary effect. They conclude that "Wright's Law" (experience curves) persists across time and products, even though varying policy interventions have occurred across technology sectors.

Another factor to consider is how local costs vary from global levels. For example, at present US solar PV costs are considerably above those in Germany and globally on average. One study concludes, "Lower average installed costs in Germany suggest that deeper near-term cost reductions in United States are, in fact, possible and may accompany increased market scale. It is also evident, however, that market size alone is insufficient to fully capture potential near-term cost reductions, as suggested by the fact that the lowest-cost state markets in the United States are relatively small PV markets. Targeted policies aimed at specific cost barriers (for example, permitting and interconnection costs), in concert with basic and applied research and development, may therefore be required in order to sustain the pace of installed cost reductions on a long-term basis." (LBNL 2012: 43)

In conclusion, an important part of the RTEP scenario building process will be to assess how policy and market drivers may affect the doubling rate of solar PV over the next two decades. But the experience curves themselves should continue as before.

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