Quantifying the impact of R&D on PV project financing costs

Finance | For PV to continue competing with alternative energy sources, the cost of financing solar projects must fall. David Feldman, Rebecca Jones-Albertus and Robert Margolis of the US National Renewable Energy Laboratory explore ways in which research and development can boost PV competitiveness

Although R&D has helped make PV-generated electricity cost-competitive with traditional forms of generation in many markets, studies have shown that PV electricity costs must continue to decline if it is to keep gaining market share [1, 2, 3]. Financing costs currently represent a significant portion of total PV electricity costs. We explore ways in which R&D can influence PV financing costs by removing real and perceived risks from PV projects, and we use financial models to estimate R&D's full impact on PV financing costs and levelised cost of energy (LCOE) via reduced risks [4].

Improved module testing is among the R&D activities that can help drive PV financing costs

Credit: Hanwha Q CELLS

How R&D affects financing

The cost of financing comes from debt and equity investors who fund PV project construction and operation to make returns on their investments. The return rate each investor desires—and thus the cost of capital—is impacted by a variety of factors. Supply and demand dynamics [5] and the underlying interest rate the US government charges banks play an important role in determining the required rate of return. In addition, the underlying risk of the cash flow a project receives and the risk of changes in perceived value of the asset play critical roles in determining investors' required rate of return, particularly in the long run. In general, investors require a higher rate of return to make investments that are perceived as riskier, and vice versa. Finance theory typically includes a measurement of risk (i.e., volatility) when calculating the expected rate of return for equity and debt investors in a project or company.

When financiers build financial models, they estimate their risk exposure by examining the sensitivity of returns to various risk factors. For example, financiers may look at expected project cash flows assuming an average level of production (or P50) and a production level that the project has a 99% chance of exceeding (or P99). Narrowing the gap between the P50 and P99 scenarios lowers a project's overall perceived risk.

Risks affect different sources of capital differently. Equity investors own assets or a portion of assets. They enjoy the benefits of any appreciation in asset value, but they are also exposed to any reduction in asset value. Debt investors lend money that is paid back later, and they are compensated by interest payments on a set schedule. Because of the need for cash flow certainty, the inability to benefit from asset appreciation and the exposure to risk of asset depreciation, debt investors are more exposed to cash flow and asset value volatility over the term of the loan. However, debt investors, as well as tax-equity investors, are less exposed to long-term risk than are long-term equity investors.

Based on this information, we divide the sources of PV financing costs into four categories, emphasised below in bold:

- Costs required to pay back the sources of capital (the **"cost of debt"** and the **"cost of equity"**) for providing project funds, plus profit—summing their weighted contributions to the "cost of capital."
- The amount of debt or **"leverage"** on a project; because receiving a larger fraction of funds from a cheaper source such as debt can lower the weighted average cost of capital (WACC), generally the higher the leverage, the lower the costs.
- Upfront costs or **"transaction fees"** associated with arranging funds.

R&D reduces these costs primarily by reducing risks related to uncertainty and volatility, such as by lowering the uncertainty of PV system electricity production. Reducing PV project risks can directly lower the required rate of return/cost of

R&D activity	Effect on financing cost			
	Lower risk premium	Increased leverage	Reduced upfront costs	Reduced time to close financing
Technology R&D				
Durability	√	√	√	√
Reliability	√	√	√	√
Certainty of production over time	√	√	√	√
Improved module testing	√	√	√	√
Lower system price			√	
Integration R&D				
Improved production forecasting	√	√	√	√
Advanced inverter designs	√	√	√	√
Improved communications	√	√	√	√
More integrated technology and systems design	√	√	√	√
Business practices analysis and standardisation activities				
Aggregated system performance and payment history	√		√	√
Expanded new sources of capital	√			
Lower O&M costs		√	√	
Increased available customer base			√	√
Streamlined processes, standardised procedures and documentation			√	√

Table 1. Summary of R&D, analysis and standardisation impacts on PV financing cost

capital, in accordance with finance theory [6, 7, 8]. Reduced risk can also make more investors comfortable with investing in an industry or asset class, which increases marketplace competition and thus lowers the cost of capital—and this reduction in risk has occurred for PV with the help of R&D-related policy. Ten years ago, only 5-10 institutions provided financial instruments for PV projects, but now there are 30 [4]. Finally, increasing cash flow certainty can lower WACC by increasing a project's leverage. Debt typically protects itself with a buffer of extra cash flow to account for cash flow volatility, as calculated in a project's debt service coverage ratio (DSCR); reduced risk can lower the DSCR, allowing for greater debt and a lower WACC [9].

Many R&D advances have reduced PV technology-related risks. Improvements in product design and manufacturing have decreased module failure and degradation rates [10, 11, 12], reduced power electronics failure rates within PV systems [13] and increased PV system lifetimes [14], allowing PV module companies to offer longer warranties [15] and creating more confidence in investors to make long-term investments. The PV industry now has much better tools, data, and practices than it did 10 years ago to estimate solar irradiance and PV system electricity production. R&D that results in standardised PV testing and improved due-diligence processes also has reduced financing costs by reducing the time and expense associated with closing a financial transaction.

Table 1 summarises various R&D, analysis and standardisation activities that could affect PV financing costs by reducing perceived risks, increasing competition, or making business practices more efficient.

Estimating the impacts of R&D on financing costs

We estimate the effects of R&D on financing costs differently for each of our four

R&D activities that can reduce PV project cash flow volatility	Sources of project cash flow volatility	Estimated standard deviation		
		Current	Low risk	High risk
Reducing technology risk by improving the durability, reliability, O&M, and testing of PV products **Reducing solar-resource risk through improved production forecasting**	PV system electricity production [16]	8.9% [18]	6%	14%
Reducing electricity value risk through improved grid integration	Regulatory uncertainty [19] Value of competing electricity (e.g., fuel costs, retail rates) [20, 21] Customer credit [22]	2% 17% 7%	1% 9% 3.5%	4% 43% 14%
Reducing electricity off-taker risk and energy production risk by improving data transparency related to system performance and payment history	Customer credit PV system electric production	Standard deviations already given above.		

Table 2. R&D that can reduce PV project cash flow volatility matched with sources of volatility

	Volatility by Scenario		
	Current	Low Risk	High Risk
Equity returns	20%	10%	50%
Asset value	20%	10%	50%
Debt payments (for DSCR)	10%	5%	20%

Table 3. Volatility of equity returns, asset value and debt payments for PV systems

	Current	Low Risk	High Risk
Cost of equity	10.9%	6.9%	21.5%
Risk premium	1.0%	0.1%	6.1%
Swap spread	2.3%	2.3%	2.3%
LIBOR	1.0%	1.0%	1.0%
Cost of debt	4.3%	3.3%	9.4%
DSCR	1.30	1.13	1.87
Utility-scale PV transaction costs ($/W)	$0.01	$0.00	$0.07
Residential PV transaction costs ($/W)	$0.03	$0.00	$0.19
Leverage	56.8%	58.2%	50.9%

Table 4. Calculated financing costs in current, low-risk and high-risk scenarios

cost categories. For transaction fees, we simply estimate the change in upfront costs. To estimate the cost of equity, we use the capital asset pricing model (CAPM), varying risk by the volatility of equity returns. To estimate the cost of debt, we use the Merton Model (a derivation from the Black-Scholes option pricing model), varying risk by the volatility in asset value. To estimate leverage, we adjust the required DSCRs for P99 and P50, varying risk by the volatility in debt payments.

Before we measure the change in PV system risks, we must quantify those risks. In Table 2, we map the R&D activities that can reduce PV project cash flow volatility with measurable sources of cash flow volatility. We also provide very basic estimates of current volatilities as well as volatilities in a "low risk" scenario (in which R&D successfully removes risks) and "high risk" scenario (in which R&D is not performed or is unsuccessful in preventing the introduction of additional risk). Additional research to improve the accuracy of PV volatility estimates would be valuable.

Assuming the sources of volatility are not correlated, we can combine them by squaring the standard deviations, summing those products, and taking the square root of the sum. This results in a total current PV project volatility of around 20%. We assume that total project volatility would apply to the volatility of equity returns and asset values, but volatility associated with debt payments does not include residual value risk. Because the value of competing electricity is most applicable to residual value (i.e., value after the electric contract), we remove this risk, lowering debt payment volatility to 10%. Table 3 summarises the current, low-risk, and high-risk volatilities, rounded to the nearest 5% value in part because the estimated volatilities in Table 2 are based on limited data and are not comprehensive.

We use the National Renewable Energy Laboratory's System Advisor Model (SAM) and assumptions listed in our report [4] to calculate the impact that a change in inherent risk and transaction costs could have on PV LCOE via a change in equity and debt risk premiums, project leverage and upfront financing costs. Because leverage is an important factor in CAPM and Merton Model calculations, we iterated the models collectively until all leverage values in SAM were consistent with those used to calculate the cost of debt and equity.

Results

For each scenario and U.S. PV sector (utility-scale and residential), Table 4 summarises our estimated financing costs. Figure 1 summarises the resulting unsubsidised LCOEs for utility-scale systems. As shown in the figure, R&D-driven changes to financing costs could lower LCOE about 20% in the low-risk scenario, or prevent an LCOE increase of about 90% due to the high-risk scenario.

Our calculations for the cost of

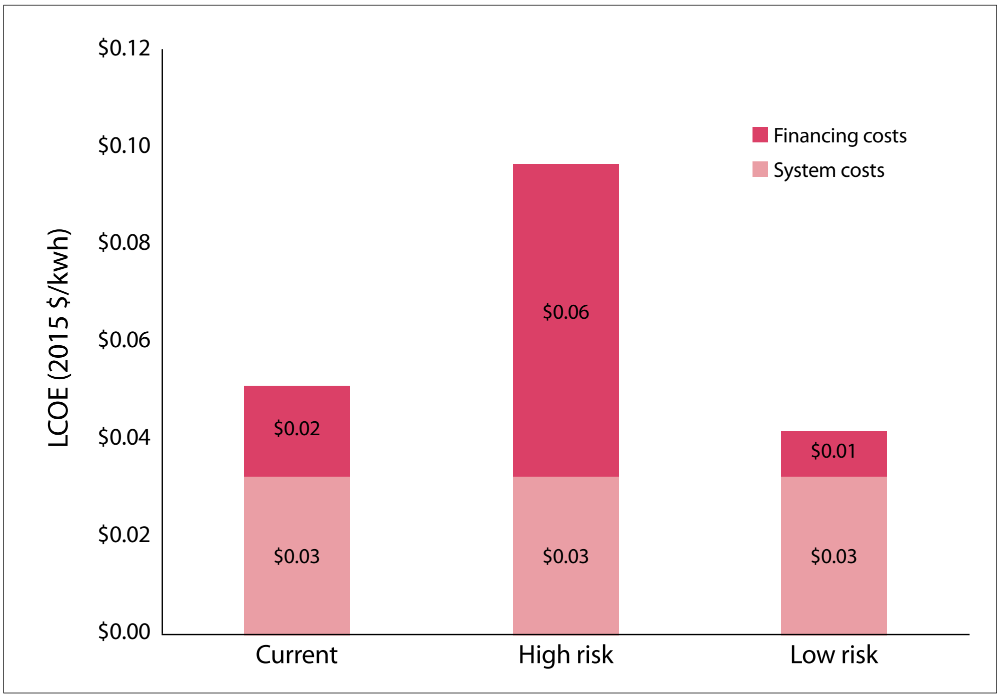

Figure 1. LCOE of a 2015 utility-scale PV system under current, high-risk, and low-risk financing scenarios

financing for current, low-risk, and high-risk scenarios are relatively consistent with comparable industries. The current values are fairly consistent with those reported in the National Renewable Energy Laboratory's 2016 PV project finance benchmark report [23, 24]. The low-risk WACC of 4.1%, calculated from the values in Table 4 (and a tax rate of 35%), is fairly consistent with the average WACC for other industries with low risk profiles, such as real estate (4.5%), transportation (5.9%), and utilities (3.5%) [25]. The high-risk WACC of 13.7% is fairly consistent with other higher-risk investments coming exclusively from private sectors, such as mezzanine debt (10-24% cost of capital) and private equity (20-28% cost of capital) [26].

Our assumptions about uncertainty and volatility are based on limited data, and future data-collection and analysis efforts would strengthen the results. That said, our research clearly shows that R&D activities can help reduce and remove many of the risks and procedures that currently exist for PV investments. Financing costs are fundamentally driven by expectations about risk and return as well as the friction necessary to complete a financing transaction. The more certain financiers are of receiving cash flows from projects—and the less variability is expected—the lower the cost of financing. R&D focused on improvements in technology, system integration, and business practices can create more certainty and reduce expected variability in energy production and the resulting cash flow for the life of PV projects. Further, R&D activity that adds to or sustains the consumer and grid value of PV assets could result in higher investor returns with less expected risk—and thus lower PV financing costs.

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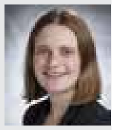

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[19] Although PV benefits have been reduced in many states, including reductions to the credit customers receive for exported energy through net-metering programs, these changes have primarily affected PV systems built after the adjustments, because existing systems have been grandfathered into the previous programs. Because we have no data on such regulatory change, for this analysis we simply assume a one standard deviation probability (i.e., a 68% probability) that one state (2% of states) will make a regulatory change over the life of an asset that takes away or significantly reduces the benefits being received by existing PV systems. In the low case we halve the uncertainty and in the high case we double the uncertainty.

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