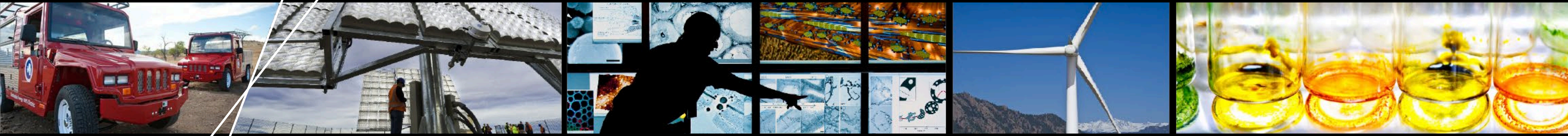
Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions



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- **New Approach**
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  - Generalized finance modeling in ReEDS
  - New finance treatment related to solar ITC
- **Scenario Results**
- **Conclusion**

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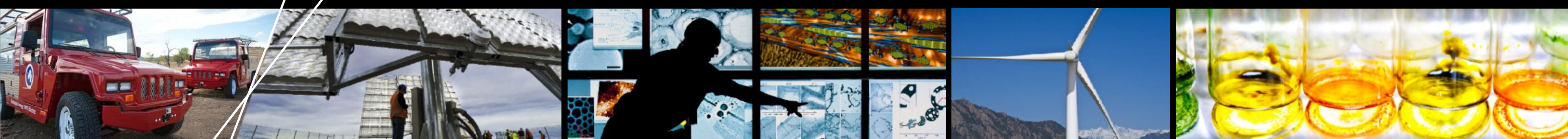
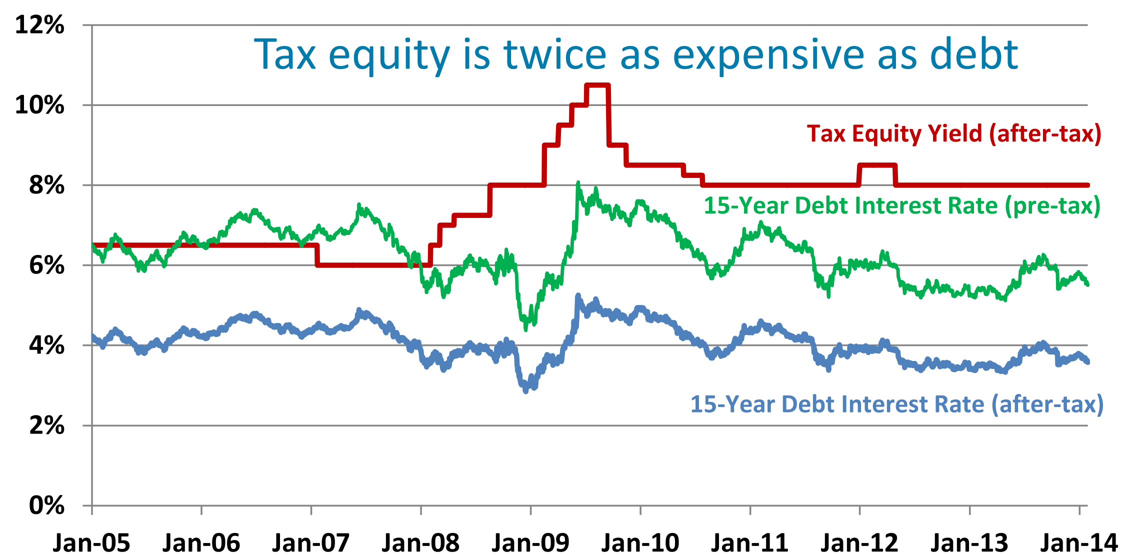


Motivation & Background

Motivation & Background

- An investment tax credit (ITC) of 30% for solar projects was established in the Energy Policy Act of 2005, has been extended a number of times, and is currently set to decrease to 10% (and remain at that level) for utility-scale and commercial projects and be eliminated for residential projects at the end of 2016.
- LBNL's 2014 "cost of tax equity" work (see next slide) found that the scheduled ITC reversion would likely shift project finance away from expensive tax equity and towards cheaper forms of capital like debt – "softening the blow of a reversion."
- While the LBNL work estimates the impacts of this project finance shift on PPA prices, what remains unknown are the *deployment implications* of such a shift.
- Prior to this project, the NREL ReEDS model (and, to our knowledge, other long-term investment models, e.g., EIA's NEMS model) did not have the capability to account for this likely financing shift, which limits its ability to capture the full impact of future policy scenarios.



Source: Bolinger 2014

Key findings from LBNL's "Cost of Tax Equity" Analysis

1. **The report looks at a variety of plausible policy scenarios and finds that, in most cases, the importance of tax equity fades as even those sponsors without tax appetite are better off financing with debt and carrying forward unused tax benefits.**
2. **This policy-induced financing shift leads to a lower cost of capital, which in turn partially mitigates the otherwise negative impact of the policy shift.**
3. **Modeling is done on an "all else equal" basis (e.g., assuming no reduction in the cost of tax equity), but tax equity investors could always lower their target returns in order to remain competitive under these scenarios.**
   - If they do, this would only impact findings about *how* projects are likely to be financed (e.g., whether with tax equity or debt) – the resulting PPA prices would not be any different than reported.
   - Some have opined that cost of tax equity might actually *increase* post-reversion if tax equity is asked to provide the same amount of capital per project (as more of its return would be cash-based and riskier).
4. **This work highlights the importance of the debt market (coupled with a sponsor's ability to carry forward unused tax benefits) as a backstop against which tax equity must compete in order to remain relevant, as well as the usefulness of this methodology as a way to place bounds on the likely range of market impacts stemming from future policy changes.**

Bolinger, Mark. (2014). *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives*. LBNL-6610E. Berkeley, California: Lawrence Berkeley National Laboratory. http://eetd.lbl.gov/sites/all/files/lbnl-6610e_0.pdf

For the present FY15 study, the NREL/LBNL team has:

1. **Conducted a literature review of approaches and assumptions used by other modeling teams and consultants with respect to solar project financing**
2. **Developed and incorporated an ability to model the likely financing shift away from more expensive sources of capital and toward cheaper sources as the ITC declines in the ReEDS model**
3. **Use the "before and after" versions of the ReEDS model to isolate and analyze the deployment impact of the financing shift under a range of conditions.**

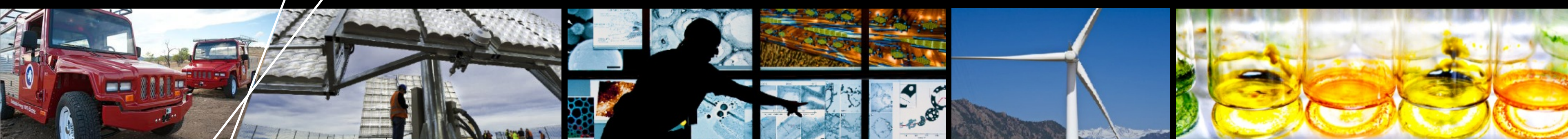
Notes

- The scope of the analysis is on utility-scale solar (UPV) only; distributed generation deployment is exogenous to ReEDS. In the current analysis we model a single rooftop PV projection for all scenarios.
- The analysis is based on the ReEDS model version v.2015.1 with some updates. This is an earlier version of ReEDS than the one that will be used for the "On the Path to SunShot" study.
- The focus of the analysis is on 2016–2030 solar deployment. There may well be longer-term implications, but these are not explored herein.

Summary of Key Outcomes

- **New Functionality:** ReEDS can now model different debt fractions for utility solar depending on the ITC amount level (the method is applicable to other technologies and tax credits, e.g., wind PTC, as well).
- **Minimal Impacts:** The modeled "financing" shift softens the effect of ITC reversion on UPV prices and deployment, but the overall impacts are small (<300 MW/year) under most scenarios modeled.
- **Other Market Factors**: Near-term UPV deployment is much more sensitive to continued UPV prices reductions. RPS or other policy drivers for UPV can also play a more major impact on future UPV deployment.
- **Future Work:** The model capability developed can be applied to other long-term models and a more complete set of scenarios can be modeled to further inform the impact of future technology, market, and policy conditions on utility-scale solar deployment.

- **Key Caveats:**
  - The ReEDS model lacks foresight and therefore does not deploy UPV in anticipation of changing policies.
  - The interest rate used in ReEDS reflects a long-term rate that are possibly higher than rates considered for projects today.
  - ReEDS models "typical" projects in a region and does not represent the "best" possible projects therefore may underestimate deployment.

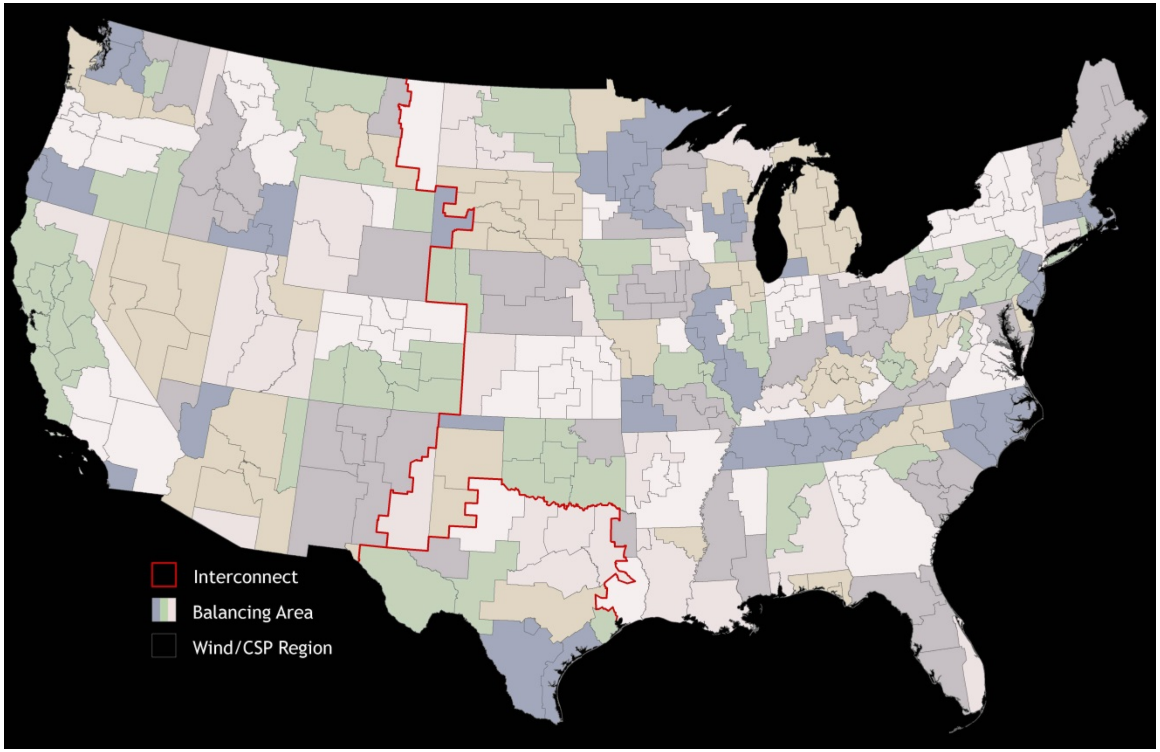


Approach & Assumptions

(Regional Energy Deployment System Model)

A spatially and temporally resolved model of capacity expansion in the U.S. electric sector.

Designed to explore potential electric sector growth scenarios in the United States out to 2050 under different economic, technology, and policy assumptions.



ReEDS Financing Assumptions (prior treatment)

- **All costs (including new capacity investments) are considered on a <u>20-year Net Present Value</u> (NPV) basis**
  - The economic lifetime (20 years) is separate from the physical lifetime
  - Levelized costs of energy (LCOEs) are <u>not</u> used in ReEDS; the objective function finds the system-wide least cost solution subject to physical, resource, policy, and other constraints
- **ReEDS uses generalized financing assumptions that are <u>standardized across technologies</u> (see table)**
  - A Weighted Average Cost of Capital (WACC)—a function of the interest rate, Rate of Return on Equity (RROE), debt fraction, and tax rate—is used as the discount rate for the NPV evaluation in ReEDS
  - Technology-specific considerations—including the Modified Accelerated Cost Recovery System (MACRS), tax credits, and construction period—are factored into the all-in or effective capital costs but the WACC is uniform across all technologies
  - The WACC is also used to calculate 20-year NPV of variable (fuel and O&M) costs and in other ReEDS cost metrics (e.g. regulated return for electricity price calculations)
  - All else being equal, a higher WACC favors fuel-intensive technologies (e.g., NG-CC) while a lower WACC favors capital-intensive technologies (e.g., solar and wind)
  - Because ReEDS is designed for long-term analysis, financial parameters are intended to represent typical long-term inputs **(e.g. interest rates are higher than today)** and are not designed to reflect different project risks

Financing parameter	Values used in recent analyses
Interest Rate – Nominal	8%
RROE – Nominal	13%
Debt Fraction	50% (60% in SSVS1)
Combined State and Federal Tax	40%
WACC – Nominal (Real)	8.9% (6.2%)
MACRS (non-hydropower renewables)	5 years
MACRS (nuclear, combustion turbines)	15 years
MACRS (other fossil, hydro, storage)	20 years

Model Changes to Reflect Potential Financing Shifts

ReEDS modified to enable technology-specific and time-varying debt fractions. Two primary changes to the assumed debt fractions:

1. **Set default debt fraction to 60% (to be applied for all technologies *except for solar* when a 30% ITC is available, e.g., utility-scale solar prior to 2017)**
2. **Set utility-scale solar debt fraction to 40% when the 30% ITC is available and change to the default value (60%) when the ITC steps down to 10% (e.g., after 2016)**

Notes:

- **ReEDS' long-term perspective remains: interest rate and RROE are unchanged from prior**
- **Changing WACC only applies to solar capital costs (by influencing the effective capital cost multiplier)**
- **20-yr NPV of solar O&M costs rely on the same default (lower) WACC discount rate similar to variable and fixed costs for all non-solar technologies**
    - This is needed to ensure that solar's value in displacing non-solar (e.g., natural gas) generation is on equal footing
    - Due to the small impact that solar O&M costs have on total (including capital) costs, changing this assumption would have little effect on model decisions
- **The same approach is applied to wind when the wind production tax credit (PTC) is available.**

Method and assumed debt fractions are consistent with the ranges suggested by existing literature (11 sources reviewed)

- **Most other data sources suggest a debt fraction that is greater than 50% (and up to 70%), particularly with greater weighting applied toward the IPP-perspective**
- **Only 3 sources (including LBNL) report financing effects associated with the changing ITC; in all 3 sources, lower debt fractions (of 30–45%) under the 30% ITC increase (to 5–61%) when the ITC reverts to 10%.**

Source	Report Title	Source Year	Debt Fraction				Notes
			Default	IOU	IPP	w/ Solar ITC	
BNEF	H2 2014 LCOE report	2014	70%	-	-	-	
CEC	Estimated Cost of New Renewable and Fossil Generation in California	2014	-	45%	60%	-	
E3/WECC	Capital Cost Review of Power Generation Technologies	2014	-	45%	-	44.9% at 30% ITC 60.6% at 10% ITC	PV Tracking >20 MW
EEI	2014 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry	2014	-	56.7%	-		For IOUs only
EPRI	Program on Technology Innovation: Integrated Generation Technology Options 2012	2013	-	50%	-		
EIA	The Electricity Market Module of the National Energy Modeling System: Model Documentation 2014	2014	45%	-	-		
EPA	(IPM Documentation)	?	55%	-	-		Relies on 75/25 IOU/IPP blend.
Lazard	Lazard's Levelized Cost of Energy Analysis—Version 8.0	2014	60%	-	-	30% at 30% ITC 60% at 10% ITC	
MIT	Future of Solar	2015	60%				
NETL	Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects	2011	-	50%	70%		
LBNL	An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives	2014	-	-	-	44.4% at 30% ITC 58.1% for 10% ITC	

The effective value of the ITC is lower when changes to the debt fraction are considered

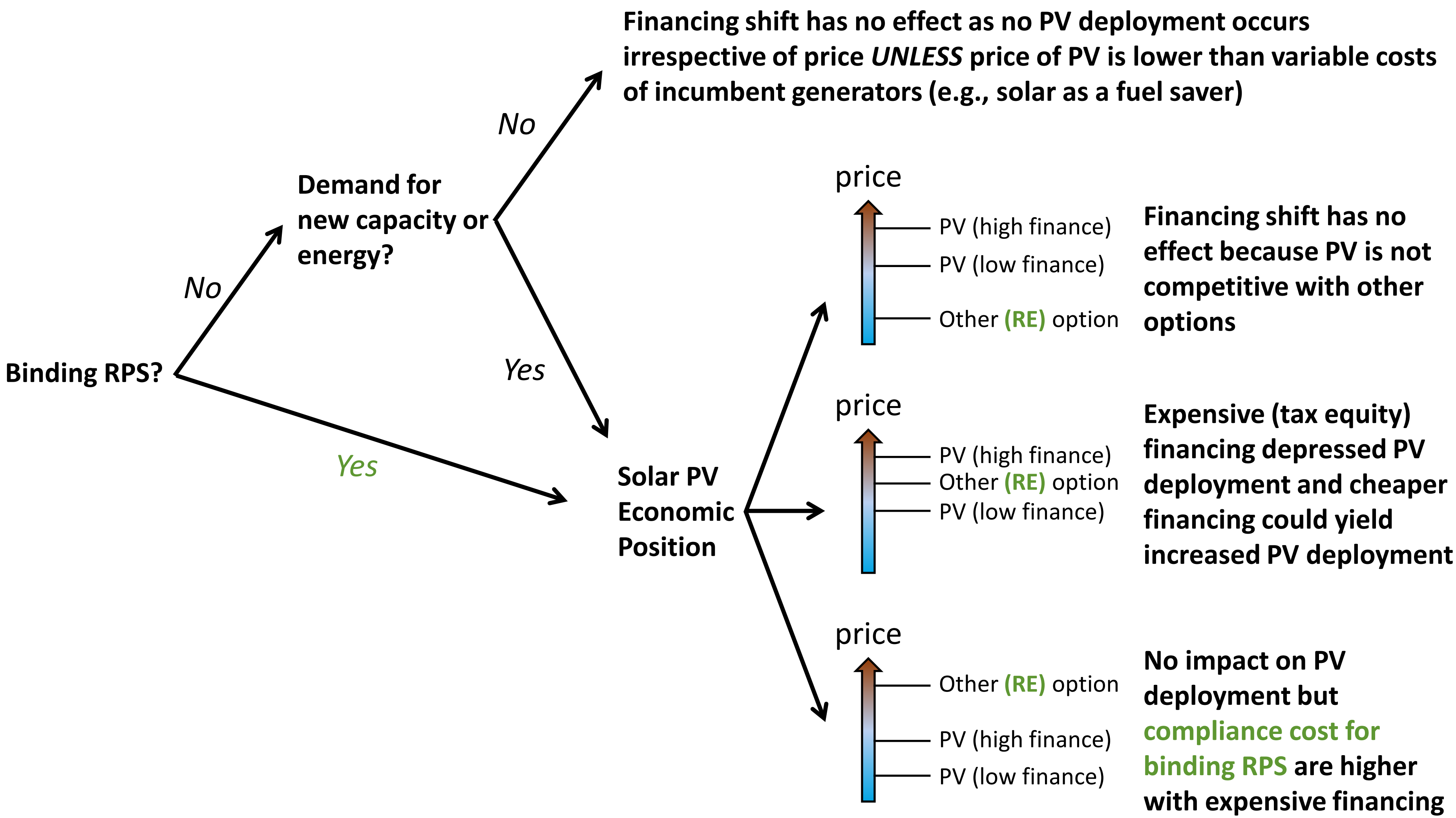
- **LCOE comparisons used to conceptually demonstrate the effect of financing shifts***
- **"Intermediate" assumptions for 2016 (see slide 16): $1,780 kW_DC overnight capital cost, $15/kW-yr fixed O&M, 24% capacity factor (AC output over DC nameplate capacity), 5-yr MACRS, other standard ReEDS financing assumptions**

LCOE $/MWh	50% debt	60% debt	40% debt
No ITC	94	88	100
10% ITC	83	78	89
30% ITC	62	58	66

- **Old treatment (50% debt) results in a LCOE shift of $21/MWh (35%) when the ITC reverts**
- **New default debt fraction (60%) results in a LCOE shift of $20/MWh (35%)**
- ***New shifting debt fraction (from 40% to 60%) results in a LCOE shift of $12/MWh (18%)***

* *The comparisons on this slide are illustrative only as ReEDS does not use LCOEs directly*

Under the ITC reversion, when would financing shifts impact deployment?



Real situations are more complex due to multiple competing options, solar carve-outs, state differences, non-economic decisions, etc. However, the chart demonstrates the regimes under which the modeled financing shifts might matter.

Key Caveats of Analysis and Methodology

- The applied method does not directly reflect higher cost of tax equity (i.e., the methodology alters the capital structure, but not the cost of capital, in response to the ITC reversion), nor does it capture the diversity of other possible financing mechanisms.
- Decision-making in ReEDS is based on a system-wide least-cost approach that does not take into account revenue maximization for individual developers.
- Non-economic or non-policy decisions to build PV are not considered (e.g., using PV as a fuel price hedge, green markets); conversely, supply chain or permitting constraints/challenges associated with new deployment are not fully considered in ReEDS.
- ReEDS includes limited foresight and, as such, would not, for example, deploy greater (potentially lower price) PV in 2015–16 in anticipation of a lower (10%) ITC post-2016.
- The Clean Power Plan and other potential or anticipated energy regulatory policies are not considered.
- None of the scenarios reflect a forecast or prediction of future deployment by NREL, LBNL, DOE, or the U.S. government.

Key Modeling Assumptions

UPV capital costs (2014$/kW-DC)*	2016	2018	2020	2030
Baseline	$1,860	$1,670	$1,480	$1,240
Intermediate	$1,780	$1,505	$1,235	$1,115
SunShot	$1,700	$1,340	$990	$990

- **Capital costs for utility-scale PV are shown on the table; fixed O&M costs are assumed to be $7.7-20/kW-yr based on year of construction; variable O&M costs are assumed to be zero; capacity factors vary by region**
- **Cost and performance assumptions for non-solar technologies are from the Annual Technology Baseline (ATB) 2015 mid-line assumptions**
- **Electricity demand growth and fuel prices are based on the AEO 2014 Reference**
- **Rooftop PV adoption trajectories are determined exogenously using the dSolar (formerly SolarDS) model; installed rooftop PV capacity is assumed to total 10 GW in 2016, 13 GW in 2018, 19 GW in 2020, and 58 GW in 2030**
- **Unless otherwise noted, current energy policies modeled only (e.g., EPA's proposed Clean Power Plan is excluded in all scenarios)**

** Capital costs are loosely based on a combination of preliminary estimates from the NREL Annual Technology Baseline and the SunShot Vision Study, and adjusted based on current market data. The cost trajectories span a range of possible futures, but no specific case reflects NREL's or DOE's current goals or projections.*

Scenario Framework

Except for "policy" sensitivities, only current policies are modeled (30%→10% ITC after 2016, no Clean Power Plan). See slide 16 for standard assumptions.

Scenario Label	Utility Solar Technology Costs	Solar Project Capital Structure	Policy
Baseline-debt50	Baseline	50% debt all years	
Baseline-debt60	Baseline	60% debt all years	
Baseline-lodebt	Baseline	40% solar debt all years	
Baseline-shift	Baseline	40%→60% solar debt - 2017	
Intermediate-lodebt	Intermediate	40% solar debt all years	
Intermediate-shift	Intermediate	40%→60% solar debt - 2017	
SunShot-lodebt	SunShot	40% solar debt all years	
SunShot-shift	SunShot	40%→60% solar debt - 2017	
NoRPS-Base-lodebt	Baseline	40% solar debt all years	No state RPS
NoRPS-Base-shift	Baseline	40%→60% solar debt - 2017	No state RPS
NoRPS-Int-lodebt	Intermediate	40% solar debt all years	No state RPS
NoRPS-Int-shift	Intermediate	40%→60% solar debt - 2017	No state RPS
Extend-lodebt	Baseline	40% solar debt all years	30% ITC extended through 2020
Extend-shift	Baseline	40%→60% solar debt - 2021	30% ITC extended through 2020

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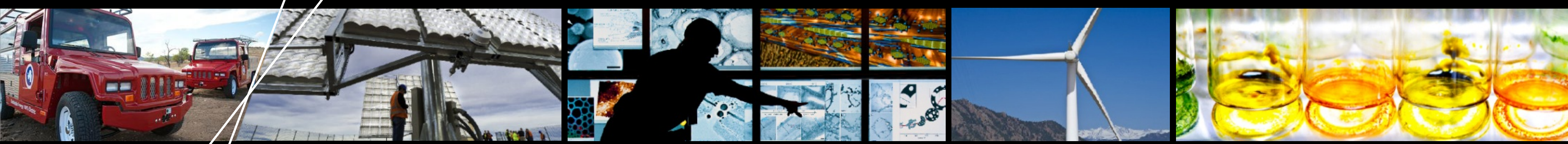
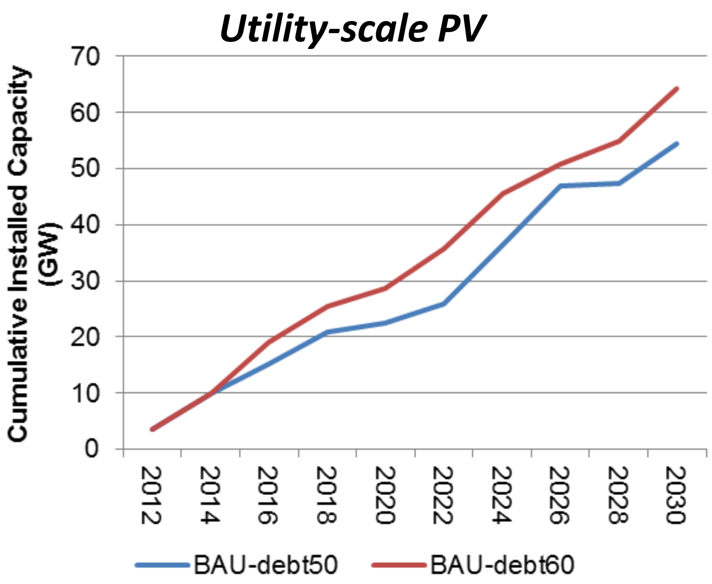
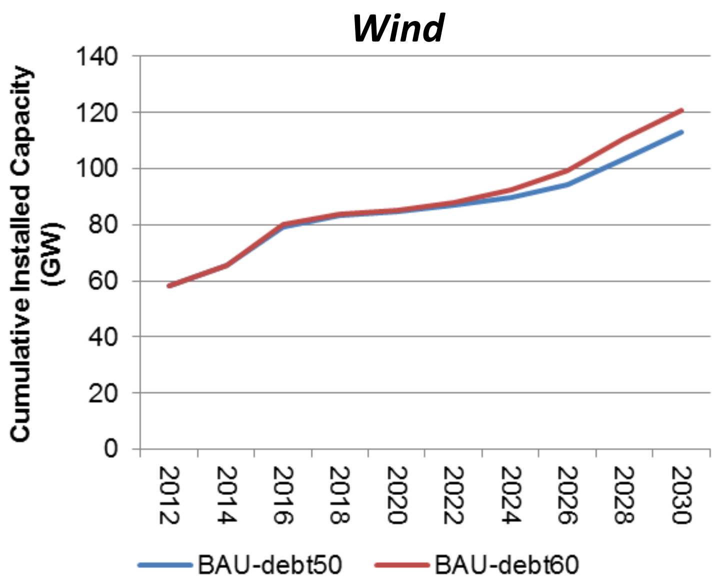


Scenario Results

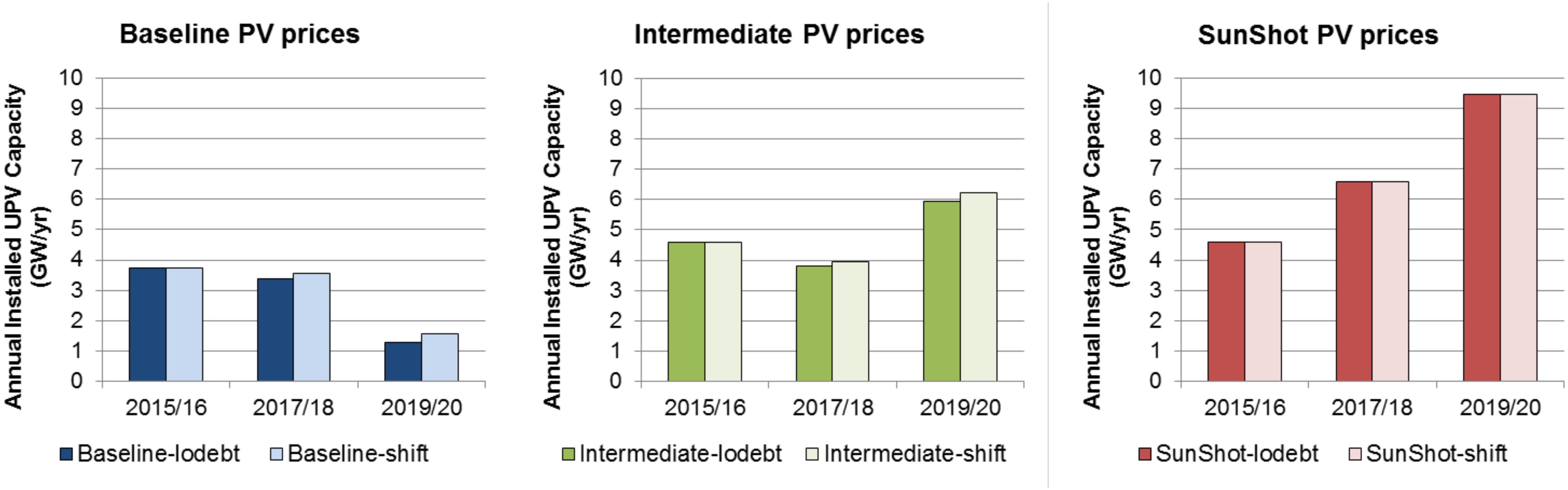
Changing ReEDS default debt fraction from 50% to 60% leads to increase in RE deployment at the expense of fossil generation





- **Above comparison ignores any anticipated financing shift as a consequence of changing ITC values.**
- **Differences are most pronounced in the longer term.**
- **Assuming a higher debt fraction gives a WACC discount rate that is more favorable to capital-intensive technologies at the expense of fuel-intensive ones.**
  - Fossil generation also uses 60% debt, but is not as capital-intensive as RE and so does not benefit as much from the extra leverage
- **Scenarios shown use the higher "Baseline" PV price projections only (see following slides for results using other technology projections).**

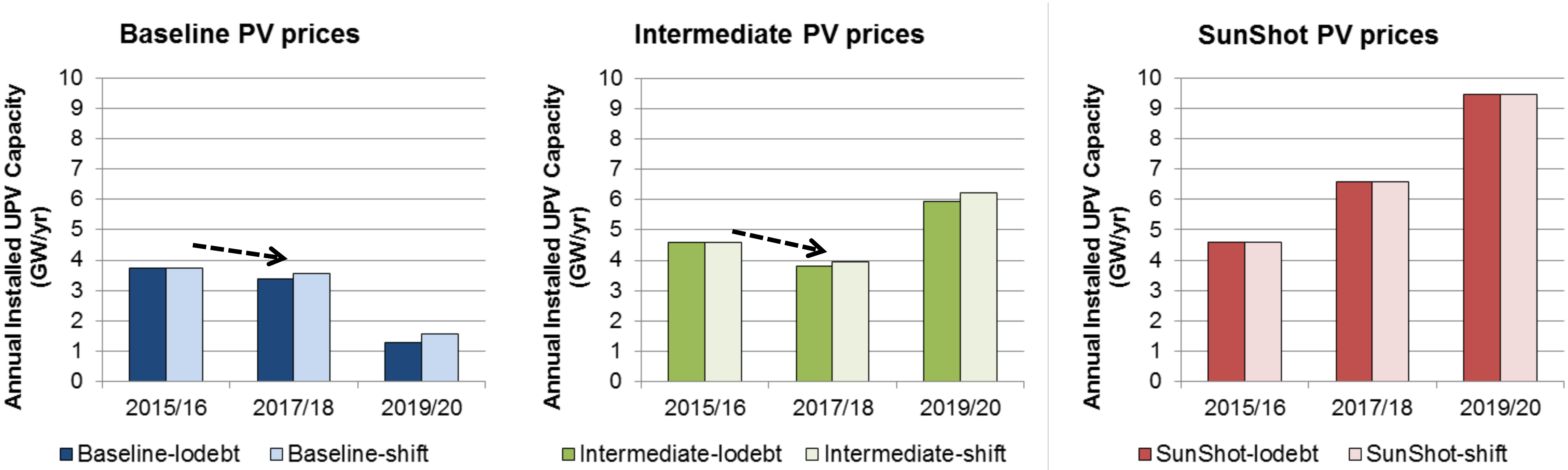
Isolating the deployment impact of financing shifts



Notes:

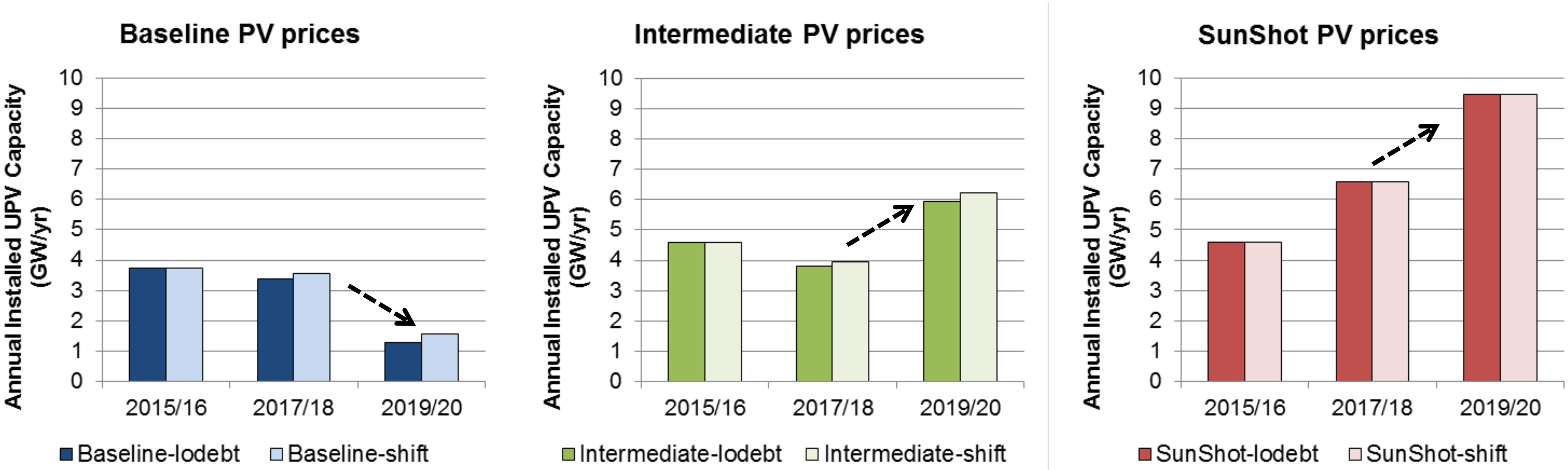
- **Charts show average <u>annual</u> deployment over each two-year period from ReEDS**
- **Solar ITC is assumed to decline to 10% after 2016 for all scenarios shown**
- **60% debt fraction is assumed for all non-solar technologies**
- **"shift" scenarios reflect anticipated financing shift from 40% debt to 60% debt post-ITC; "lodebt" scenarios provide counterfactual by assuming the debt fraction for solar projects stays at 40% for all years irrespective of ITC level**

Solar deployment could be impacted by financing shifts, but is more sensitive to broader assumptions about future tech costs



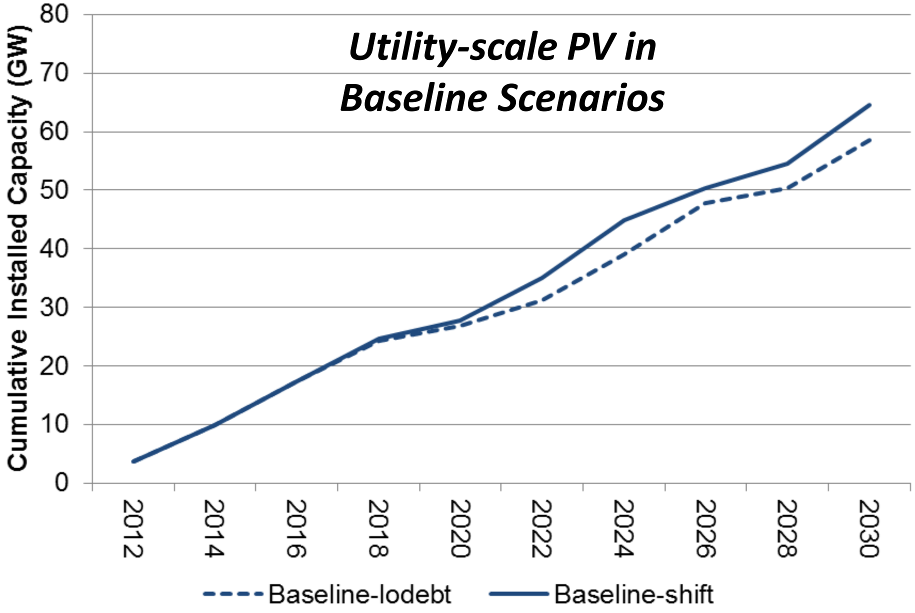
- **The decline of the ITC after 2016 is estimated to reduce annual 2017/18 UPV deployment except under SunShot cost trajectories.**
- **Under Baseline PV prices, shifting to cheaper sources of capital allows for ~180 MW/yr greater utility PV deployment in 2017/18 compared with scenarios that retain the same debt fraction after the ITC declines.**
- **Under Intermediate PV prices, the benefits of greater debt financing is estimated to result in only ~120 MW/yr of UPV deployment in 2017/18.**
- **Under SunShot PV prices, annual UPV deployment (from 2015 to 2020) is essentially unaffected by capital structure as the prices are sufficiently low that relative benefits of financing shifts do not influence deployment (but could influence *cost* of deployment).**

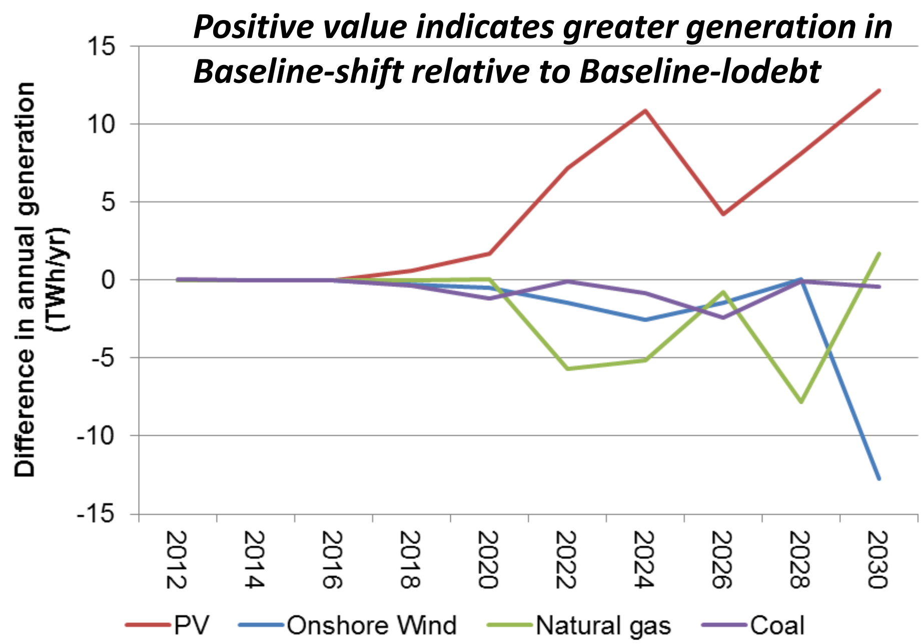
A wider range of solar deployment possibilities found by 2020



- **<u>Annual</u> electricity demand growth is estimated to be twice as high in 2017/18 compared with 2019/20 (51 TWh/yr vs. 25 TWh/yr); Demand growth is based on AEO 2014**
  - Lower demand growth also influences RPS demand for solar
- **Because of this slower growth, PV deployment declines in 2019/20 under Baseline prices**
- **Despite lower demand growth, under Intermediate and SunShot prices, annual utility PV deployment is expected to grow in 2019/2020 relative to annual estimates for 2015-2018**
- **Lower financing costs lead to 270 MW/yr greater deployment than higher financing cost scenario during 2019/20 under Baseline conditions (~310 MW/yr more under Intermediate prices); no impact (except for likely lower costs) under SunShot prices**

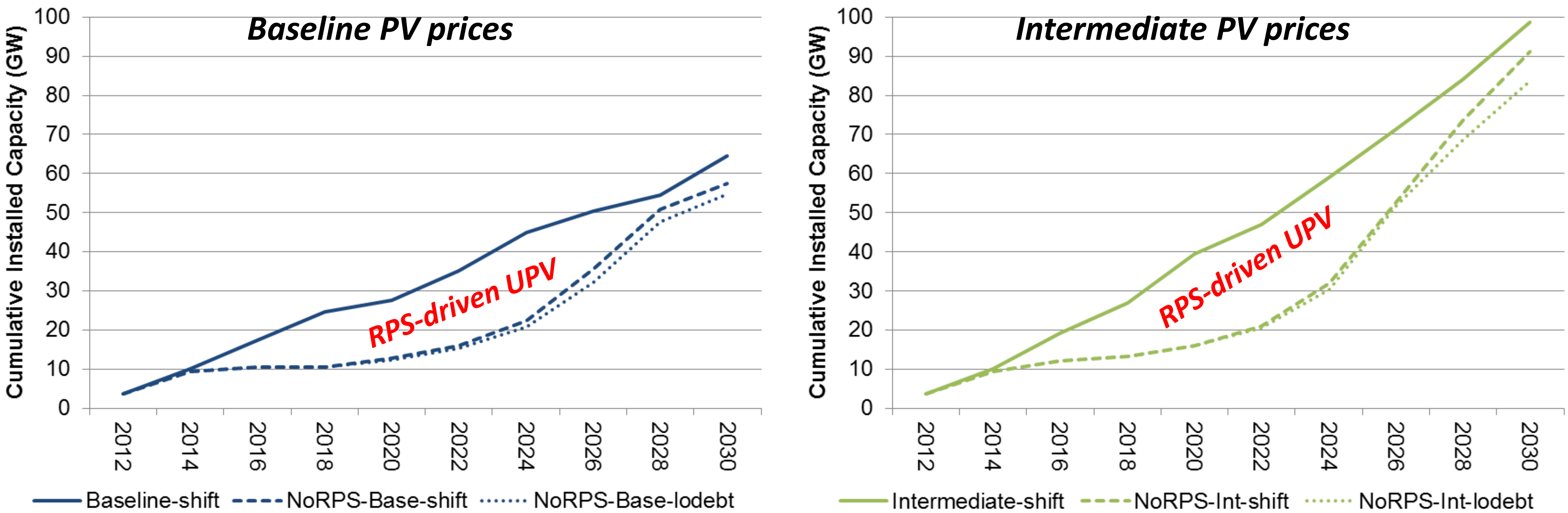
Financing shift has a larger impact in the long-term
relative to a scenario where expensive solar financing is "permanent"





- **By 2030, shifting to cheaper sources of capital result in >6 GW of UPV deployment**
- **Increased UPV deployment comes at the expense of fossil (primarily natural gas) and wind generation**
- **The positive impact for solar PV deployment relative to fossil and wind is a consequence of the relative capital-intensiveness of the different technologies, where higher leverage benefits capital-intensive solar PV**
- **Qualitatively similar results found for Intermediate and SunShot price scenarios**

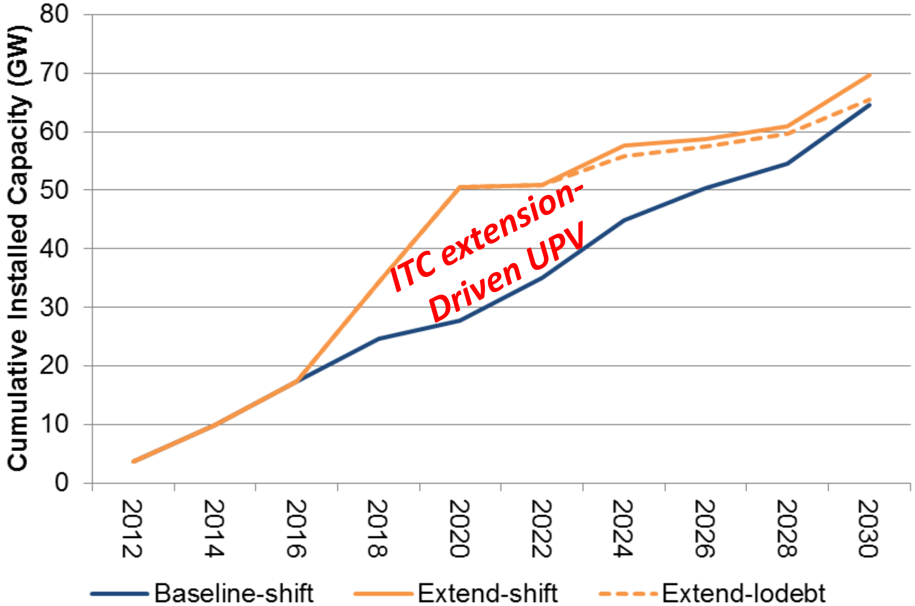
ReEDS estimates that RPS requirements are primary drivers of new UPV installations through 2020

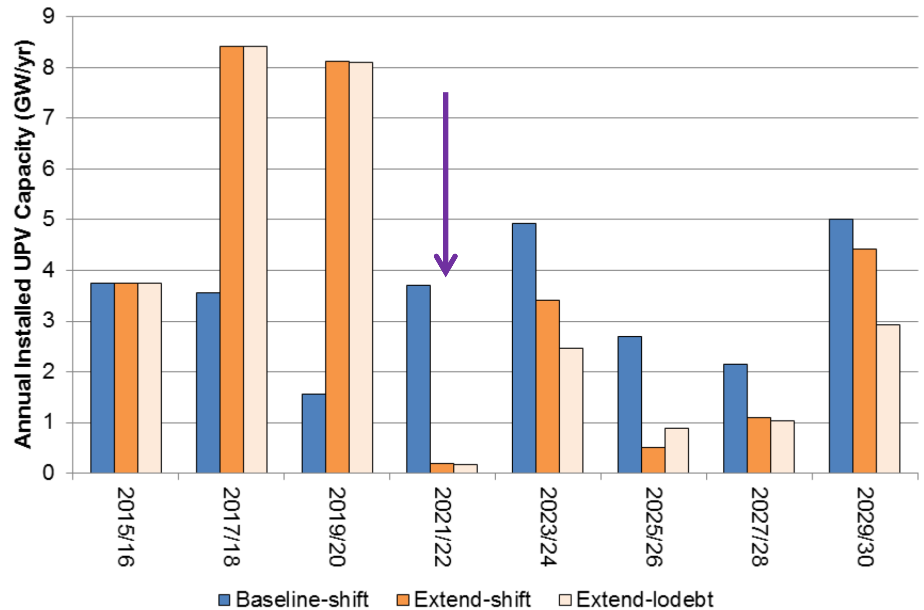


- **Nearly all 2015-2020 UPV deployment is driven by RPS requirements under Baseline prices; however, under Intermediate prices, nearly 7 GW of non-RPS UPV is deployed from 2015 to 2020 (with ~3 GW in 2015-2016).**
  - GTM/SEIA 2014 notes at least 5.7 GW of UPV currently in development outside of RPS
- **Financing shift has little impact on non-RPS driven UPV deployment by 2020**
- **In the longer-term, current RPS policy is less of a driver for new UPV; the benefit of the financing shift amounts to ~3 GW additional non-RPS UPV by 2030 under Baseline assumptions and nearly 8 GW under Intermediate assumptions**

Extending the 30% ITC through 2020 leads to accelerated and somewhat greater UPV deployment…

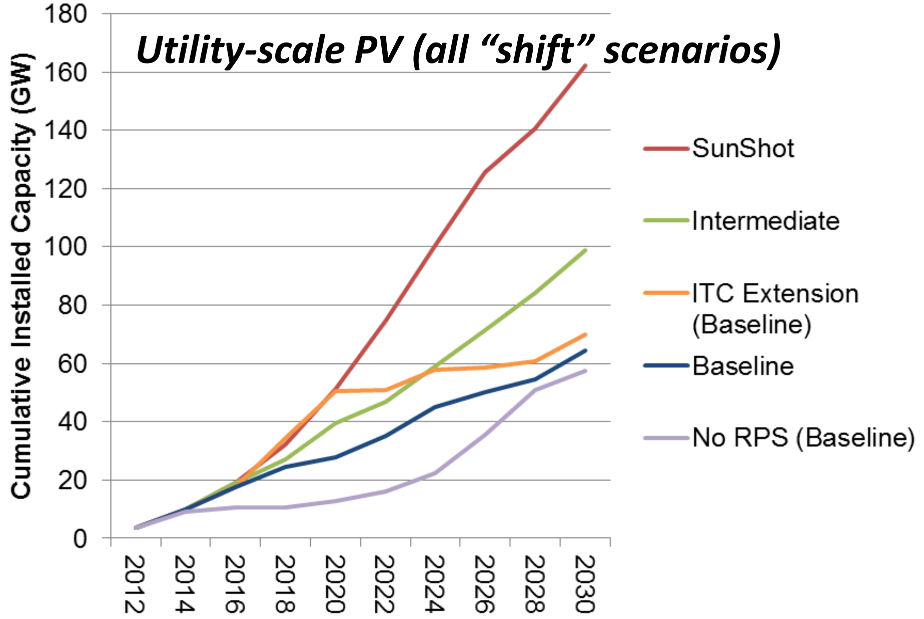
Utility-scale PV – Baseline prices





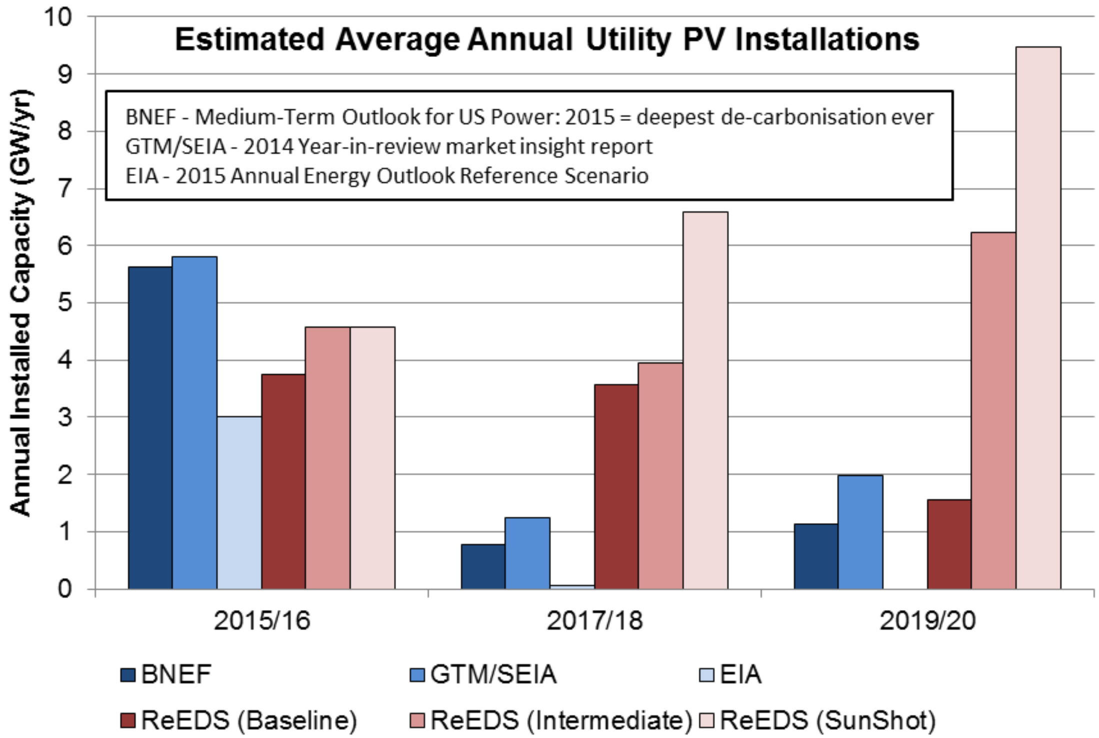
- **…but introduces a steeper cliff in 2021/22 annual deployment when the ITC steps down to 10% <u>independent of assumed debt fraction</u> (as demand for new UPV capacity appears limited in the early 2020s)**
- **Greater leverage leads to more UPV in the long run (~4 GW by 2030)**
- **More generally, extending the 30% ITC accelerates deployment, possibly garnering environmental and other benefits, but has limited impact on long-term cumulative UPV capacity**

Summary of utility PV deployment results



- **Across the scenarios modeled (except for the artificial "No RPS" scenario), cumulative UPV ranges from 27-51 GW by 2020 and 65-162 GW by 2030**
- **The long-term market potential for UPV is highly sensitive to technology advancements, whereas tax credit extensions only have short-lived impacts**
- **Current RPS policies appear to be a primary driver of near-term UPV deployment, but has more limited influence in the long run**
- **While not modeled, the EPA CPP, coal plant retirements, or other policy or market changes can also dramatically impact future UPV deployment**

Comparison of ReEDS estimates (all "shift" scenarios) with other projections



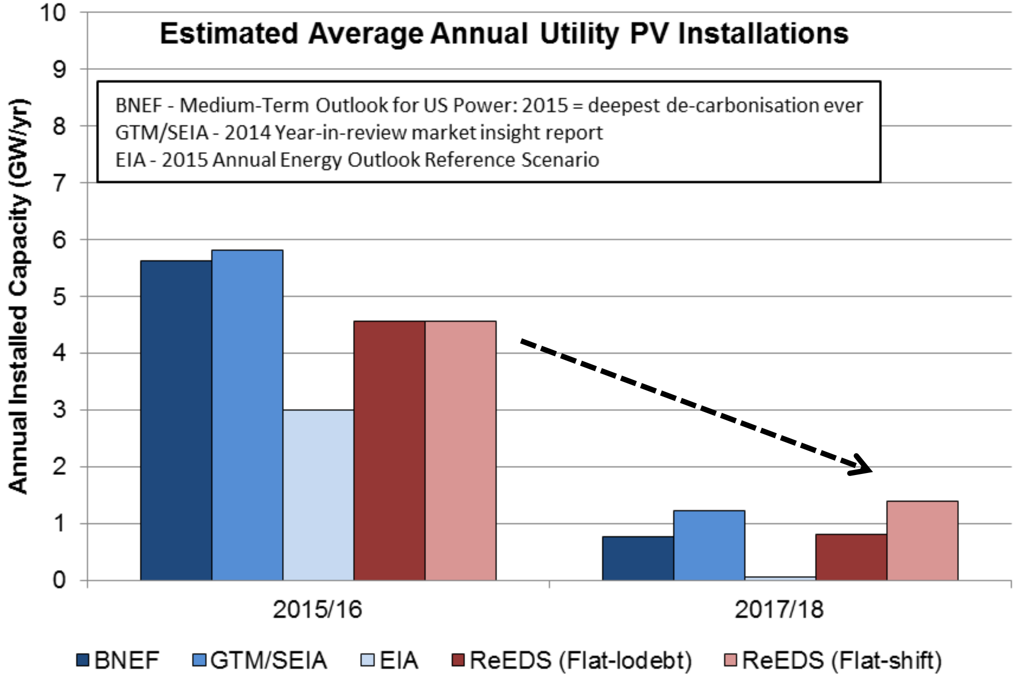
- **ReEDS' 2015/16 utility PV deployment estimates are within the range of other projections (but lower than BNEF and GTM/SEIA)**
- **ReEDS generally finds greater UPV deployment occurring in 2017-2020, possibly due to:**
  - ReEDS' inability to accelerate deployment in anticipation of changing incentives (i.e., lack of foresight, which may explain lower 2015/16 build); and
  - Other differences in key assumptions (for one possible explanation, see next slides)

Additional scenarios modeled to identify potential sources of differences between ReEDS and other projections

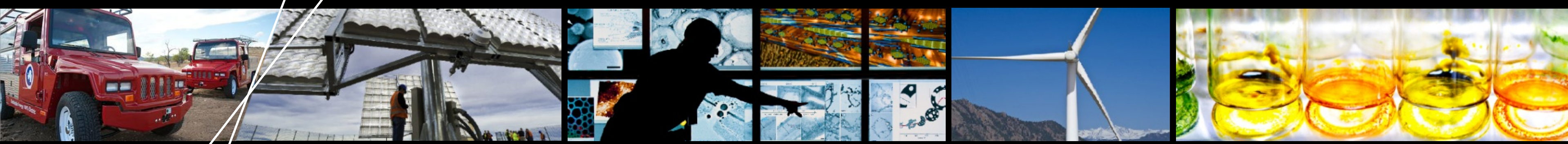
- **In all ReEDS price scenarios (Baseline, Intermediate, SunShot), UPV prices are assumed to decline between 2016 and 2018 by an amount that is similar to (but in the opposite direction of) the LCOE impact from the ITC reversion, given the financing shift (e.g., ~$12/MWh on an LCOE basis, see slide 13)**
- **As a consequence, ReEDS finds that annual deployment differs very little in 2017/18 compared with 2015/16, and that the financing shift has only a minor impact on deployment**
- **To try and isolate the impact of the financing shift (i.e., without making other changes to UPV's competitive position), we evaluated two scenarios where 2016 UPV prices under the Intermediate assumptions ($1780/kW-DC) remain fixed through 2018:**
    1. "Flat-lodebt" scenario maintains a 40% debt fraction for solar for all years
    2. "Flat-shift" scenario models the debt fraction changing from 40% to 60% after the ITC reversion

Note: we do not have access to the underlying UPV price assumptions used by BNEF and GTM/SEIA, therefore cannot compare directly. EIA's UPV price projections decline slower (and prices are greater) than those used in ReEDS.

The flat UPV price scenarios demonstrate:



- **A much sharper drop in annual deployment after the ITC reversion (> 3 GW/yr or ~70% decline in 2017/18 relative to 2015/16)**
- **A larger impact of the financing shift (580 MW/yr greater UPV deployment in 2017/18 relative to the 40% debt fraction or "lodebt" scenario)**
- **Closer alignment with BNEF and GTM projections in 2017/18 – indicating that UPV price declines used by BNEF/GTM may be more pessimistic than those used in the core ReEDS scenarios, or indicating that if UPV prices do not continue to decline, financing options will have larger implications on post-ITC solar deployment**



Conclusions

Key Outcomes

- **A method to represent some of the effects of a shift in project finance away from expensive tax equity and towards cheaper forms of capital like debt that would likely accompany the solar ITC reversion was developed and implemented in ReEDS**
- **Using ReEDS scenarios with this improved capability, we find that this "financing" shift would soften the blow of the ITC reversion; however, the overall impacts of such a shift in capital structure are estimated to be small and near-term UPV deployment is found to be much more sensitive to other factors that might drive down UPV prices**
- **Continued UPV price reductions might counter the negative deployment impact of the ITC reversion, particularly if the reversion is "softened" by a shift towards cheaper sources of capital**
- **The model capability developed can be applied to other long-term models and a more complete set of scenarios can be modeled to further inform the impact of future technology, market, and policy conditions on utility-scale solar deployment**

- **Key caveats:**
    - The ReEDS model lacks foresight and therefore does not deploy UPV in anticipation of changing policies
    - The interest rate used in ReEDS reflects a long-term rate that are possibly higher than rates considered for projects today
    - ReEDS models "typical" projects in a region and does not represent the "best" possible projects therefore may underestimate deployment

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