Legislative Council of the Parliament of Victoria
Committee on Environment and Planning

QUESTION ON NOTICE [from HANSARD PROOF transcript]

Ms BATH: Thank you, Chair, and thank you, Professor Wilson, for being so professional today in all your responses. Professor, you spoke about levelised cost of electricity—and this might be one to take on notice—and looking at a viewed system as a whole, including technical services. Now, my question goes to: it is one thing to make the energy at the factory, at the ignition point, whatever that be—wind, solar, carbon, coal, hydrogen or nuclear—it is the other thing I think have we a big problem with in Australia, our connectivity and our transmission. So I would like you, if you would not mind, to respond perhaps in writing, because we have run out of time, about some of the flaws in our connection system, our transmission system, and some of the flaws that would be overlaid by various different mixes and what needs to happen in that space.

Prof. WILSON:
…on LCOE, I provided in the materials a side-by-side comparison of two LCOE calculations that come to extremely different results, and it is just to show that you can use that metric to produce a very wide range of results. That is not its only shortcoming, and so I am happy to provide a little bit more material on that that might be helpful for the committee.

RESPONSE

In my opening remarks I noted that **LCOE is not an investment grade metric** and provided a reference to that effect from as long ago as 1995 published by the well-respected National Renewable Energy Laboratory (NREL) in Colorado, part of the U.S. Department of Energy.

The **original reason** for the creation of the LCOE metric was to allow a **like-with-like comparison** between generation types with high capital cost and low operating (fuel) cost on the one hand (e.g. hydropower or nuclear) and those with low capital cost and high operating (fuel) cost on the other hand (e.g. gas-fired power plants or diesel engines, or even coal plants).

The **great advantage** of the LCOE metric is that it is **very simple and easy to use**. A system-wide model is not required. People adept at performing approximations to discounted cash flows can even do LCOE calculations as mental arithmetic. For most people, spreadsheet software is needed and a single sheet is sufficient. The examples in the two tables provided on pp.7-8 of the materials I submitted in advance to the committee are generated using a simple Excel file.

Viewing the tables side-by-side illustrates the very wide range LCOE estimates that can be produced just by tweaking a few input assumptions within known ranges for uncertainty or contextual factors. The result tends to be more sensitive to some inputs than others. In the example provided, the key inputs changed were:

• **overnight capital cost** (from the CSIRO estimate of $16,000/kW or $16M per MW down to an first order simple exchange rate adjusted approximation of the NuScale Nth of a kind estimate of AU$4,800/kW or $4.8M per MW; equivalent to AU$11.52 billion down to $3.456 billion, respectively on a lump sum basis)

• **construction period** (from 60 months to 36 months—I note there is a typo in my submission where Table 1b should read 3 years, not 5, but the calculations are not affected)

• **interest during construction** (IDC), which flows through from the previous two inputs

• **project contingency**: 30% for first of a kind and 10% for Nth of a kind (based on the AACE)

• **process contingency**: 10% for a new technology and 0% for mature technology (AACE)

• **weighted average cost of capital** (WACC) from 6.0% per annum to 5.3% per annum

• **capital recovery period** from 30 years (‘long’ business horizon) to 60 years (technical life)

• **fixed operating and maintenance cost** from $200,000/MW to $100,000/MW and

• **plant capacity factor** from 80% to 90%

Results tend to be sensitive to the overnight capital cost (particularly given the range of values being contested) and the plant capacity factor. There is a *1/x* relationship between plant capacity factor and LCOE. Plant capacity factor is, by definition, a value between 0 and 1. Annual maintenance (the Planned Outage Rate or POR) and occasional events where a plant automatically ‘trips-offline’ for safety reasons (the Forced Outage Rate or FOR) mean that 90% is a very high capacity factor for most power plants. The best run nuclear plants in the world can achieve about 92% plant capacity factor. Dividing by a fraction increases the mathematical result hyperbolically. Therefore, reducing a plant’s annual capacity factor will increase its LCOE.

If a plant is always dispatched when available, then its capacity factor will equal its availability factor. For most plants that is not the case. In a system (whether market-based or traditional), many plants, especially those with higher operating and fuel costs, may be available but dispatched with a capacity factor that is short of their availability factor. Dispatch is not binary (on or off), but can vary on a continuum between any minimum stable generation level and maximum output. Reasons that a plant is always dispatched when available may include: low variable costs; or traders offering output to the market at low, zero or even negative prices.

Wind and solar plants—which can't control their output and have zero short-run marginal costs of production (no fuel cost, low other variable costs)—tend to offer their generation to the market at zero or negative prices (the negative of their Renewable Energy Certificate revenues).

This gives rise to one of the dynamics that is observable in Australia's National Electricity Market (NEM) whereby coal plants find their annual capacity factor is reduced as their output is displaced. That spreads their fixed costs over fewer hours, which is the same *1/x* mathematical phenomenon that happens in an LCOE calculation when the capacity factor is reduced.

There are many weaknesses and shortcomings of the LCOE metric.

The first is that **LCOE cannot properly be used to compare a dispatchable generator with a non-dispatchable generator**, because the two are not offering the same service to the system or market. Electricity is the ultimate real time commodity (generation must occur at the exact instant of consumption). As a result, the economic, financial and market value of a unit of energy (MWh) can and does vary enormously by the time of day, day of the week, and season of the year. (Value also varies by location.) It is possible in theory to combine technologies (e.g. solar PV and batteries or wind plus pumped hydro), calculate the LCOE of the combination and compare that with the LCOE of dispatchable plant meeting the same load shape, but that is rarely done.

Ms Bath's question refers to the 'ignition point' but it might be more usual to refer to the 'injection point' or 'connection point' of a generator to the grid. Power system people usually talk about the cost of generation 'at the busbar' or 'at the generator terminals', usually to make it clear that they are talking about energy sent out (i.e. excluding anything used inside the plant, for the offices, etc, or for the electronics and controls on wind turbines, for example, which require a little bit of continuous power supply), and not including any costs of or energy losses within the high voltage transmission and low voltage distribution networks.

We now naturally begin to think about **system level issues**, which brings us to the second major category of weaknesses and shortcomings of LCOE. There are a very large number of items in this category, each with cost implications. At this point, the great advantage and strength of LCOE—its simplicity and avoidance of a system model—becomes its weakness and limitation.

Here it is important to note that **there is no single power system model or category of power system model able to represent the system completely**. Multiple models are required, each focused on a particular time horizon and time resolution, from the short- to the long-term. It is not practicable to link such models together into one giant super-model. When used well, power system models can provide valuable insights but experienced engineers and decision-makers are still required to interpret results, apply judgment and make decisions. The first chart attached provides a flavour of the universe of power system models. This is intended to put in context the results from any one model, highlighting why no model is able to provide 'the last word' on a power system. There are always open edges, even on technical questions.

Ms Bath asked about 'connectivity and our transmission.' It is common for people to refer to 'system integration costs.' Lion Hirth has defined a three-part schema comprised of **'grid-related costs' for the effect of generator locations; 'balancing costs' for the effect of uncertainty; and 'profile costs' representing the effect of variability**.[1] These are useful categories and we find in our research, consistent with Hirth, that the aggregate of the three categories of integration costs increases non-linearly with increasing shares of variable renewable energy, consistent with the '1/x problem.'

The three-part schema is shown in second slide, with indicative ranges in US$/MWh from the literature for wind and solar variable renewable energy (VRE) *at 30 to 35% share* of annual energy. The next slide shows a snapshot of papers for which it has been possible to identify integration costs at a given share of VRE (some papers report other variables such as decarbonisation, but not VRE share, for example. Several things should be noted here:

- 30 to 35% is relatively moderate VRE share, approximately equivalent to the annual capacity factor of wind generation, but costs are already non-trivial at that point
- much of the literature stops very far short of high to very high (50 to 100% VRE) that is discussed outside the leading international peer-reviewed energy economics journals
- the costs shown in the third chart include only profile costs, not grid and balancing costs
- there is wide disagreement in the literature about the magnitude of profile-related integration costs, but the shaded area shows agreement on the general relationship
- 'grid costs' include both 'shallow' and 'deep' transmission costs: the former being the plant-to-nearest-point on the high voltage network, the latter including the flow-on need for network reinforcements and interconnectors between regions (Vic-SA, Vic-NSW and Vic-Tas for example in the case of Victoria in the NEM)

- ‘balancing costs’ include frequency control and ancillary services (FCAS: covered by eight markets that operate in parallel with the 5 minute/half-hourly energy spot market, in which prices have also been increasing), inertia and other aspects costs associated with ensuring sufficient system strength

There is widespread understanding that some form of energy storage is required to transform VRE from a capacity factor of about 15% (fixed panel solar PV in Victoria south of the Great Divide) or 25% (two-axis tracking solar in high quality inland Northern Australia) or 35% (onshore wind) or more (roaring ‘40s Tasmanian or offshore wind) up to 100% baseload, or 70% grid average load or even simply to time-shift to match low load factor residential load.

What is less well appreciated is that the use of balancing for storage needs to be performed across many time horizons, and that **no single storage technology is suitable for all time horizons and scales of deployment**. The fourth slide shows this, and compares with the built-in storage of conventional fuel energy sources (in the form of reserves and resources through to stocks) as used in plants with rotating machinery that provides inertia for system strength.

The fifth chart illustrates **the balancing challenge that must be achieved** in large AC power systems across twelve orders of magnitude from milliseconds (operational real time) to a century (long-term system planning and climate and energy policy). The time horizons chart corresponds approximately to the model typology in the first slide. Many of the solutions proposed to manage century-scale risks introduce significant problems and risks now. My explanation of this final chart can be viewed in the recording of a webinar of the Energy Systems Integration Group (ESIG) hosted by AEMO, for which I facilitated a discussion panel on market design, available to view here: www.esig.energy/event/esig-down-under/.

Many of the technical problems now emerging are barely even defined yet. The webinar provides some flavour of this. Australian experts (at AEMO, the AEMC and elsewhere) have recently begun to address issues of ensuring sufficient inertia and other aspects of system strength. It is not yet known whether it will be possible to define system strength with a degree of quantification sufficient to allow (yet another) parallel market to be established.

It appears that other looming ‘over the horizon’ issues have not even begun to be discussed. For example, beyond power systems, research and development work on decentralised engineering control theory and system applications (including in my school at UQ) continues, but is far from a mature field. There is not yet a well-established and mature paradigm for decentralised control in general, and certainly not one for large AC power systems. Meanwhile on the system itself, the deployment continues at a rapid pace of *grid-following*, inverter-based DC-to-AC generation with no inertia and digital control systems, accompanied by the retirement of *grid-forming* AC generation with substantial analog physical inertia. Deployment of behind-the-meter distributed energy resources has not to date been required to adhere to the first principle of engineering control theory, which is that *observability* is a necessary pre-condition for controllability. The power system has continued to function so far (we are 'getting away with it'). Yet symptoms are beginning to appear in parts of the Eastern Australian system that suggest this may become an issue. Problems of this nature in Northern NSW and South East Queensland were presented at the *Future of Electricity Markets Summit* in late 2019, an event at UTS in Sydney sponsored by the Energy Security Board, the International Energy Agency and the Australian National University. The costs of dealing with such issues are currently unknown, but would need to be added to all of the cost categories noted above. LCOE certainly falls very far short of representing the full system costs.

The successful deployment of low to moderate shares of wind and solar energy show there can be a place for those resources in the mix. However, putting all of the generation eggs in a basket of resources with very low annual capacity factor risks inviting significant technical and reliability problems and/or very high costs in the future.

Notwithstanding the uncertainties already acknowledged, one can't help but notice that the magnitude of early estimates of the costs of VRE integration, *at high to very high system shares*, may well be as large as, or larger than many estimates of the environmental externalities (such as the shadow cost or 'social cost of carbon') associated with the generation that VRE seeks to displace, notably coal, and further in the future in net zero emission scenarios, natural gas.

That observation—both the magnitude *and* the uncertainty—underscore the value inherent in *allowing as soon as possible the creation of real options* for the possible future deployment of nuclear energy in Victoria, and Australia more generally.

Notes

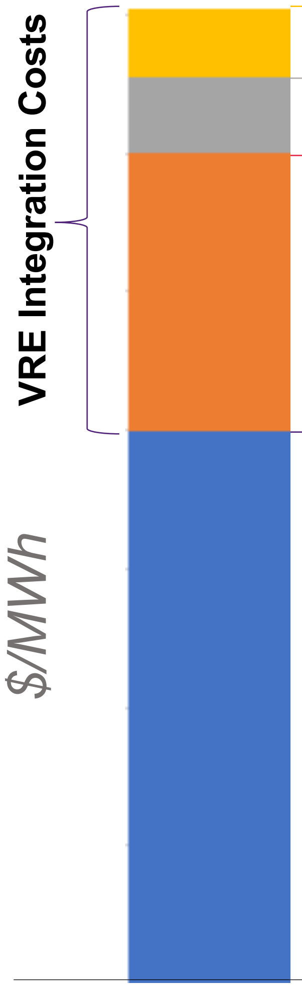
[1] Hirth, Lion, 2012a. *Integration costs and the value of wind power. Thoughts on a valuation framework for variable renewable electricity sources*. USAEE Working Paper 12–150 and Lion Hirth, 'The market value of variable renewables: The effect of solar wind power variability on their relative price,' *Energy Economics* **38** (2013) 218–236.

Overview and basic typology including some examples of power system models

Type of Model	Distribution Industrial Networks	AC Transient Electrical Network	DC Network Flows	Electricity Generation System[1]	Hybrid	Whole Energy System	Economy-Energy-Emissions	Integrated Assessment Models	Annual Energy Balancing
Scope	**detailed** power system models					**broad** energy … economy … emissions models			
Main purpose/s	system stability, reliability & resilience	fault stability & system resilience	network capacity & system strength	planning, dispatch, costs, prices	<—combination—>	primary fuel mix, emissions policy	high-level policy and strategic insight	energy, CO_2 and other GHG emissions	energy adequacy, CO_2 emissions
Objective function	meet reliability criteria at least cost	meet reliability criteria at least cost	meet reliability criteria at least cost	cost minimisation or profit maximisation	cost minimisation subject to constraints	cost minimisation subject to constraints	welfare maximisation general equilibrium	mitigation v adaptation optimisation	balance supply and demand
Method	engineering equations	engineering equations	engineering equations	marginal cost or strategic bidding	equations and 'rules'	engineering equations	equations to solve economic equilibria	energy and emission flows, some economics	energy accounting, basic economics
Mode	physical simulation	physical simulation	physical simulation	techno-economic simulation or optimisation	techno-economic market simulation or system optimisation	techno-economic optimisation	economic or techno-economic simulation	co-optimisation of the CO_2 mitigation and climate damage costs	trend projections or simple optimisation
Resolution	instantaneous	instantaneous	near-instantaneous	5 minute to hourly market intervals	annual daily shapes	time-steps usually one to five years	time-steps usually one to five years	time-steps usually one to five years	usually annual time steps
Horizon	carefully-selected snapshots	carefully-selected snapshots	carefully-selected snapshots	short (year ahead) to long (decades)	typically long: multi-year/decades	typically long: multi-year/decades	typically long: multi-decadal	typically long: multi-decadal	typically long: multi-decadal
Granularity	full LV network topology	full HV transmission network topology	full HV transmission network topology	generation unit level, key network elements	plants: actual or generic	facilities, networks and industries	typical aggregation: 20+ regions, 25+ sectors	GHG emissions by type, source, sector by region	typical model: fuel types for 100+ countries
Dataset required	Large…extremely large: network configuration	very large: transmission network configuration	very large: transmission network configuration	large: units, loads, simplified transmission	moderate: plants, load shapes, interconnectors	large: all energy systems and flows	large: simplified systems, full economy	small to large, depending on detail	small: energy flows represented simply
Key strengths	insights into AC system behaviour	insights into AC system behaviour	power flows and network loading	simulation of wholesale markets	some ability to combine perspectives	technical linkages medium-term	price-linkages, macro- and microeconomics	attempt to integrate for policy optimisation	simplicity
Main weaknesses	LV far more complex than HV networks mathematically	only 'snapshots' & very resource-intensive	doesn't reveal AC stability issues	no network-level issues, relies on scenarios	compromises required	lack of economic bounds, tend to lead to strange long-run results	large social accounting matrices, simplification of energy systems	over-simplification of systems and economy despite the complexity	limited economic 'structure', over-simplification of grid
Examples	*Siemens PSS/E DiGSILENT PowerFactory*			*EGEAS, PROMOD, NEMDE, Plexos, Spark, PowerMark, ROAM, CleanGrid, NEMRES, ANEM*	*'MEGS'*	*MARKAL / TIMES*	*BAEGEM, GTAP, OECD ENV-Linkages and other AGE/CGE models**	RICE/DICE, GCAM, FUND, MERGE, MESSAGE	*simple spreadsheet models and tables, BP energy statistics and outlook*

1. Electricity generation system models may focus particularly on the dispatch of a fleet of power generation plants to meet demand, or on the planning for the addition and retirement of power plants over time, or or some combination of the two, either in separate models or in a single model.

VRE system integration costs (Rioseco, 2020, categories based on Hirth, 2013)



Grid costs: Transmissions costs/upgrades,investments (~ US$ **2-12** /MWh at 30-35% VRE share)

Balancing costs: VRE Uncertainty. Short term forecast errors. FCAS.(~ US$ **1-10** /MWh at 30-35% VRE share)

Profile costs: associated with the temporal variability of VRE **(~** US$ **30-40** /MWh at 30-35% VRE share). Includes:

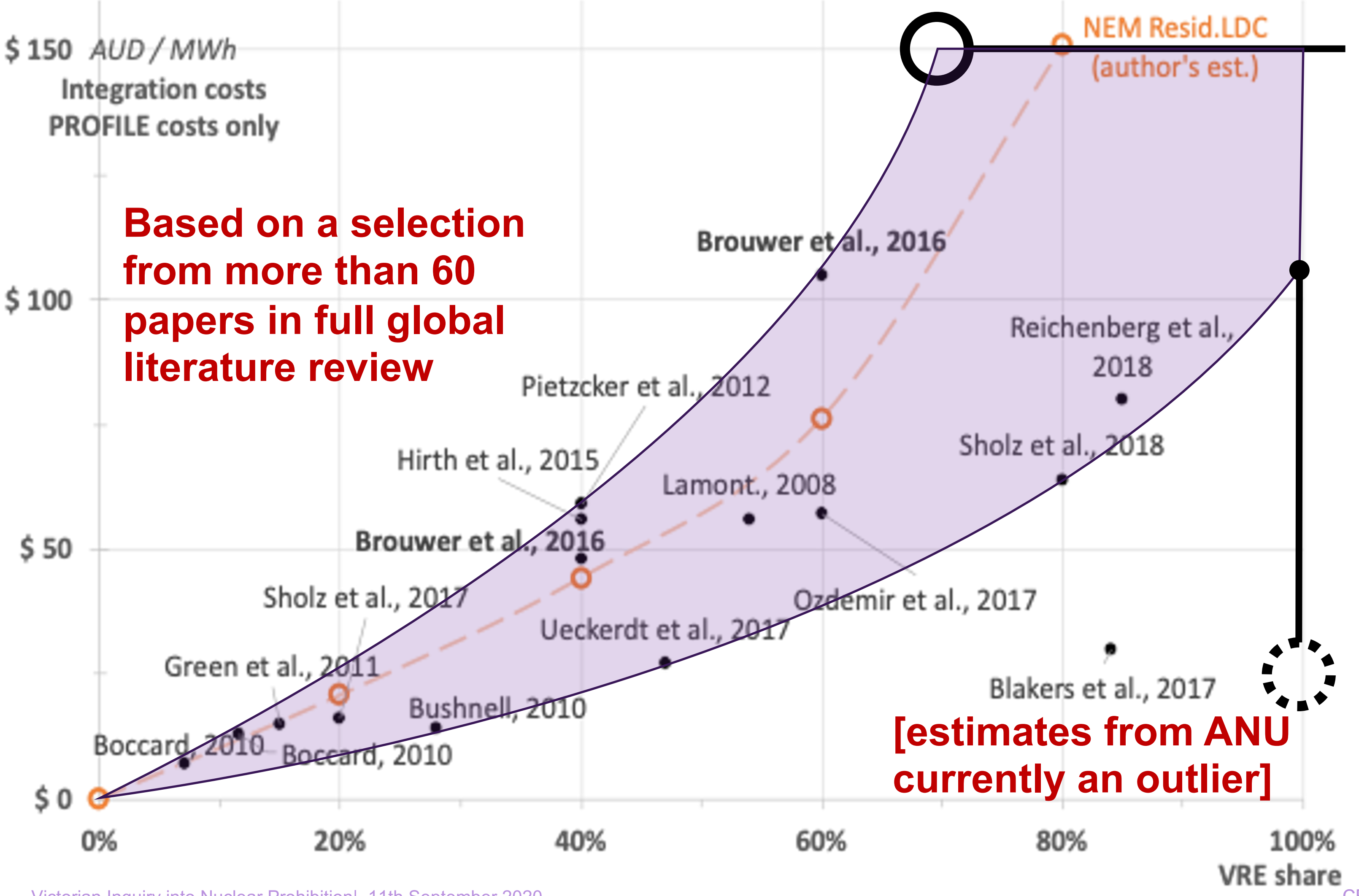
- Reduced utilization of dispatchable plants
- Ramping and cycling of dispatchable plants.
- Storage costs
- VRE curtailment

Generation Costs: Cost of electricity generation. Includes variable and fixed OPEX, fuel costs, etc.

VRE integration increases OPERATIONAL COSTS
(e.g., increase ramping of thermal plants, storage and FCAS requirements, etc)
…But also they cause additional 'indirect' costs (e.g., utilization of dispatchable plants is reduced, thus their specific generation cost increases, VRE curtailment, grid costs)

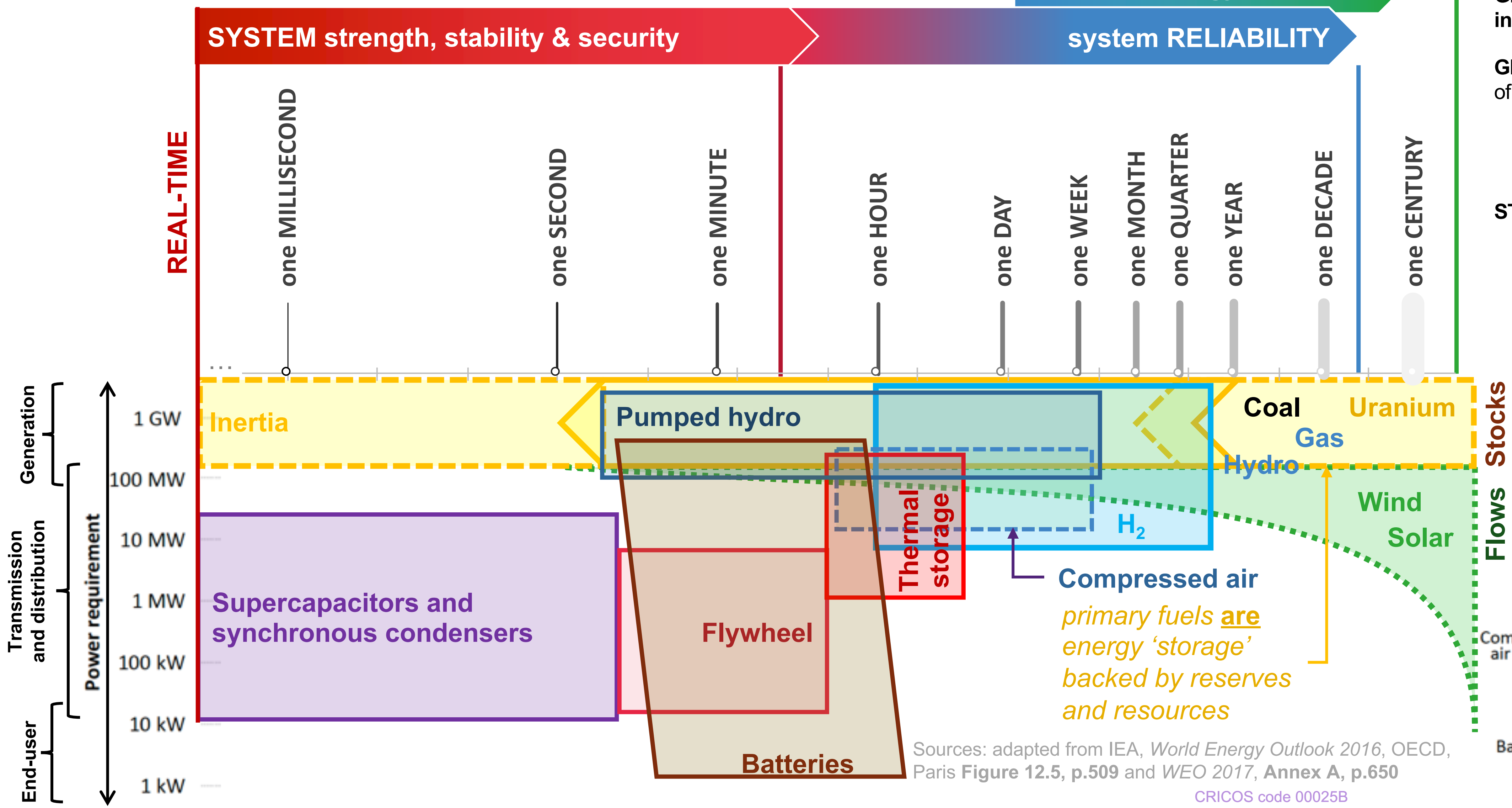
Thus, to capture VRE integration costs we need to capture the WHOLE SYSTEM implications of increasing VRE shares.

Literature review on VRE Integration costs (Rioseco, Wilson, 2020)



- **Increase exponentially with higher VRE shares**
- **Wide disparity of estimates**
- **Significant for VRE shares above ~ 25%**
- Highly **system specific**
- Mostly EU or USA studies
- **Lower bound** estimate: $25/MWh integration costs recent claim by Blakers and Stocks for 100% VRE, noted by Baldwin (Canberra, 2019)

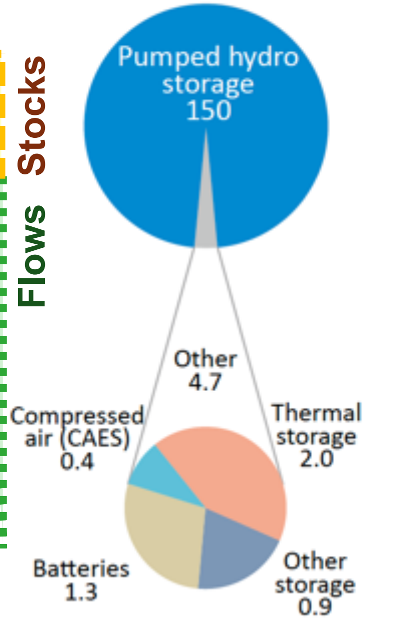
The characteristics of **ENERGY STORAGE** technologies as they apply across the span of time horizons



Sources: adapted from IEA, *World Energy Outlook 2016*, OECD, Paris **Figure 12.5, p.509** and *WEO 2017*, **Annex A, p.650**

GLOBAL electricity systems installed capacity, 2015

	GW
GENERATION	**6 414**
of which:	
hydro	1 209
wind	414
solar PV	225
CST	5
STORAGE	
pumped hydro	150
all others	4.7



The multiple **MARKETS** for electricity in the NEM across time horizons spanning 12 orders of magnitude