Turning ISP into action: submission as a comment.

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Disclaimer

This document is a non-exhaustive comment in response to the ISP process suggested by the ESB in conjunction with AEMO and the AER. It does not advocate, nor does it provide any solution, for which more work is required. To the best of my knowledge, the content herein is factually accurate and technically correct. The technical apparatus that may be cited is also referenced.

In this document I limit my comments to my area of expertise, which is economics. I purposefully do not comment on matters of Engineering nor Law.

The content of this document are my informed opinion, written on behalf of the Australian Electricity Markets Initiative (AEMI) at Monash University. In writing it I am not acting for any of the interested parties; I am not receiving any compensation, nor implied compensation. These comments should be treated as academic work: they are mine and need not represent any policy that may be pursued by Monash University.

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Summary

This short submission comments on a consultation session held by the ESB, the AEMO and the AER on "turning the Integrated Systems Plan into action", and on a draft document with the same title. These comments are by no means exhaustive, as they reflect my own interests and expertise, as well as my imperfect note-taking.

After some general remarks, the first part focuses on the consultation session held in Sydney on 5 December 2019. Most of the comments make the case that more economics should be included in the analysis, starting with selecting the correct criterion by which to evaluate investment proposals. Two important points that are raised are: (*i*) the introduction of Locational Marginal Pricing to better guide investment decisions in both network and generation assets; and (*ii*) the importance of internalising externalities when evaluating investment projects. An important consequence then is that a *welfare*-maximizing regulator is better placed than a private operator to correctly evaluate investments. Therefore the regulator (*i*) must perform the relevant cost-benefit analysis and (*ii*) the regulator is also better placed to make investment proposals. How these investment proposals are financed is independent of their social value, and so can be worked out using a variety of schemes.

The second part comments on some aspects of the draft document that underpinned the consultation session. It mostly centers on the joint-planning

obligations of TNSPs, and argues that joint planning should also include a *joint evaluation* of TNSP projects and other projects, especially generation investment projects. The reason is simple: investing in transmission alters congestion patterns; therefore its value really depends on the social cost of congestion, as evaluated using congestion prices. These prices themselves depend on the industrial organization of the generation sector, therefore that reality should also be internalized when evaluating investments. Other comments are also provided.

1 General comments

In short I believe a much more thorough examination of investment proposals needs to be programmed in the ISP, and more generally adopted by the regulators (AEMO, AER). The criterion of cost-minimization is deficient and the methods by which the AER and the AEMO suggest to evaluate investment proposals are inadequate. Pursuing in the proposed direction without re-evaluating the relevance of the criteria and methods is doomed to select the wrong investments: either outright the wrong objects to invest in, or the wrong amount of investment in possibly the right target.

Using the correct criterion (simply, social welfare maximization) is technically more demanding than the simple cost-minimization exercise. Costs are easy to understand, while utility or consumer surplus are not. However that task is not impossible and well within the realm of expertise of economists. Likewise, conducting an adequate cost-benefit analysis requires understanding the competitive environment and the industrial organization under which market participants operate. This requires detailed models, which may have to be built case-by-case depending on the specifics of the project under review. This too is an area in which economists have a wealth of expertise to share. Before committing vast amounts that rate payers will have to face for decades to come, the regulators should make the more modest investment required to better understand the economic environment under their control.

The consultation session featured much discussion about finding the "optimal" plan. This is akin to looking for the silver bullet; it is equally hopeless in an environment that is highly uncertain. Rather than attempting to pick the perfect plan, regulators should focus on designing the correct set of incentives – an attractive market design – such that private investors make decisions that are socially beneficial. For example, concerns of stability of the network may be addressed many different ways: through network investment, synchronous generation investment, batteries or software, or even appropriate market design (in the sense of the wholesale market). Which of these is better is near impossible to foretell: some of the technology may not be currently available, some may be prohibitively expensive today but potentially trivially cheap tomorrow. However, just pricing the value of network stability gives potential investors the right signal to act when the opportunity presents itself. That is what a well-informed regulator should strive for.

Finally the pace of development and which network is allowed to emerge is well within the control of the regulators, especially when handling Distributed Energy Resources. While DER sprung up independently of the regulators, the externalities they generate (network stability, network usage, supply and demand patterns...) affect *all* users. These externalities can either be priced (e.g. network access) or outright disallowed (e.g. no feed in). Likewise energy can also be priced to enhance or slow down the development of DER. These decisions are important policy variables that regulators can avail.

2 Sydney-based consultation

This section comments on selected points discussed by the panel in Sydney (5 December 2019), some of which can be found on the slide presentation. This list is not exhaustive but based on my own notes only.

2.1 Optimality criterion

The notion of optimality currently adopted in the ISP is inappropriate to sound decision-making. Investment decisions should *not* be evaluated according to a least-cost criterion subject to some kind of desirability constraint, but according to *welfare optimality*. Maximising welfare guarantees that each dollar invested delivers the largest social return. How that social return can be shared between participants is then just a matter of transfers, prices or other forms of compensation. In contrast, minimizing cost may miss out on value (consumer welfare) that consumers may be willing to pay for, and on producer surplus that TNSP may be willing to invest in. Thus in a cost-benefit analysis it is imperative to clearly define benefits – including consumer benefits – and not just costs, as cost-minimisation relies on. For example, an investment in transmission may not only bring about reliability benefits but also price arbitrage that delivers lower power prices following the investment, or other benefits to third parties.

Welfare optimality is notoriously difficult to evaluate because no one really knows the utility function of consumers (what they value, how they trade off consumption items) – whereas profits are easy to compute for producers, and costs even more so. However, as long as the welfare function is concave (a mild condition), it is well-known that *consumer surplus* is an equivalent measurement in the sense that consumer welfare is maximised if consumer surplus is maximised.

Of course measuring consumer surplus, even if easier then consumer welfare, remains onerous. It requires understanding some notion of willingness to pay of consumers, which is not observed but may be inferred. This amounts to eliciting a demand function from the market, and it is the kind of work that economists perform routinely. So much help can be availed to address this shortcoming.

2.2 "The optimal plan need not maximise net benefit".

This is clearly an oxymoron that contradicts the very idea of optimality. I presume this confusing statement arises from the fact that the future is uncertain, and that the best plan overall need not be the ideal plan in a given scenario, which may become irrelevant. Nonetheless, the optimal plan must, by definition, maximise *expected* net benefit. The problem is one of choosing a path under uncertainty; in mathematics this is a problem of stochastic optimal control. At any moment in time, the path must be optimal given the information on hand. A difficult exercise in conducting this optimization exercise is to evaluate the probabilities of states of the world at each moment in time – or at least at each time a decision must be made. To be clear, what is the probability of scenario 1 versus scenario 2? Two comments must the made in response.

1. First, fortunately it is possible to elicit these probabilities, either through surveys or prediction markets. What is the predicted solar penetration in NSW in 2021? One can ask market participants, consumers and so on, and develop an informed assessment.

2. Second, and most importantly, these scenarios may *not* be *exogenous.* Whether solar panels get installed on roofs depends, among other things, on how much they are subsidized, for example. Whether the same solar panels on roofs disrupt the grid depends on whether they are connected to it. To be clear, the regularors (AEMO, AEMC, AER) *completely* control the path of development of this market. Thus, for example, the scenarios "high solar penetration" versus "low solar penetration" should not be treated as exogenous events. Instead, the regulators should decide what is the best path, including whether or when to allow connection to the grid and so on. Scenario planning has nothing to do with this, because the regulators set the agenda.

   So, if the grid is not ready to take on solar energy there is always the option for the regulators to refuse to take it on, or to make it economically unattractive. If DER becomes a viable source of energy, the regulators may want to contemplate how to incorporate it in the grid – but need not to. Importantly, these are decisions, not exogenous events. With the appropriate design, the wholesale market can also be used to induce solar producers to internalise the externalities they impose on other users – consumers and producers.

Truly exogenous events are the price of coal, the price of gas, weather patterns and so on. It is important to distinguish exogenous events, to which probabilities may be applied, to others where the pace of development is controlled by the regulators.

2.3 Internalising externalities

In determining benefits in a cost-benefit analysis it is important to internalise externalities generated by any particular investment project on the entire system. The NEM is a network; networks are notorious for “network effects”. In broad terms, these network effects assert that an additional link to a network may have benefit beyond it immediate benefit. For example, if NSW is a net importer of electricity and QLD a net exporter, building generation capacity in NSW may not only lower prices in NSW. It may also reduce congestion on the interconnection between NSW and QLD and increase prices in QLD – which thus depresses the value of the investment. Or it may even turn NSW into a net exporter into, say, SA.

This kind of analysis *requires* moving away from the least-cost criterion to the social surplus criterion. Under least-cost these externalities are obviously ignored. It also requires detailed models of the networks and of the industrial organization of generators. Here too calling on skilled economists may help.

Another important source of externities that regulators face is intermittent energy – utility scale and household DER. Intermittent energy enhances price volatility and in some markets it even increases mean prices by displacing base load generation in some time intervals. DER also contributes to that volatility; it further alters supply patterns and affects stability, which requires investing in the grid at a cost borne by all users. Finally DER reduces overall grid utilization, however without removing the need for the grid. So average costs increase, which are borne, again, by all users.

There are many ways to address these issues: access, feed-in tariffs, technical requirements, and even markets. It is important to recognise their impact, that they speak to equity, and that they are also largely under the influence of regulators. These are not exogenous developments.

2.4 The role of Locational Marginal Pricing in informing network planning

Throughout this process little attention has been paid to the cost of electricity and nowhere is there a mention of the relationship between the ISP and the cost of power, nor between TNSP investment and the cost of power.

An important aspect of power cost, especially when it comes to network planning, is the cost of congestion on the network. This cost is captured at each node via what is called *locational marginal pricing*, or LMP. LMP has been adopted in many markets. All markets in North America rely on LMP. The EU is working on transitioning to LMP. It is important for the NEM to also transition to LMP, possibly even before committing to significant transmission investment.

LMP simply puts a price on the congestion constraint at a given node. When the node is not congested, the LMP is identical on either side of the node and the cost of congestion is zero. If congestion arises, the node becomes constrained; this is captured by a Lagrange multiplier on the constraint in the dispatch problem. LMP turns this multiplier into a price.

LMP is important because it informs dispatchers and network planners as to the benefit of relieving congestion at that node. It does so directly and unambiguously; it needs no estimation nor guesswork. Using the LMP information planners can decide whether to let TNSP invest, or rather promote generation investment – depending exactly on the price pattern, that is, on the behaviour of congestion, and its social cost. Again this requires moving away from the least-cost criterion, which cannot internalise prices nor price movements. To emphasize the point, because LMP delivers so much rich information it is an important framework to implement, *possibly before contemplating any significant network investment.*

2.5 Forecasting

Forecasting demand is an important component of any investment decision. Demand however is not exogenous; it arises from a consumption decision by customers – businesses and households. These consumption decisions are influenced by market variable: prices, substitutability, ability to connect to the grid and so on. Thus estimating demand takes more than statistics; it requires a model of consumption decisions by buyers, and it requires internalizing that regulators do influence these consumption decisions. Here too it may be useful to employ economists to construct this model.

3 Draft ISP Rule Changes document

This section offers comments in reaction to the draft that was circulated before the consultation on 5 Decenber 2019.

3.1 Joint planning obligations of TNSP (5.14)

Section 5.14 of the document makes no mention of *joint planning* between TNSP and generators, or TNSP and DEZ. However we know from academic work (Leautier, 2014 and 2013) that transmission investment may have significant effects on the utilization of current generation capacity, on power prices and on investment in generation. There is a well-known and obvious coordination problem: transmission only make sense if generation capacity is built, and conversely.

There are also more subtle, yet important effects, as shown by Leautier (2014). First, congestion between two pricing regions (e.g. zones or nodes) on a network is dynamic and may be transient, not permanent. The reason is simply that prices fluctuate: demand varies over time, generation capacity is necessarily constrained and clearing prices are determined by the marginal generator at a given time. Therefore a congested line for some prices may not be for another set of prices. This is also where LMP is so critical: LMP provides this price information, and thus informs planners of the true cost of congestion, and the true value of further investment on the congested line.

Second, transmission investment and generation investment may be substitutes or complements (or neutral) – and not simply substitutes. It may also affect different technologies (based-load and peaking), differently. The reason for this complicated pattern is precisely that congestion is transient: when the line is congested but the (cheaper) base-load technology is the price setter, the marginal value of investing in transmission is determined by that low price. When the line is not congested, investing in transmission has no social value. Finally when the line is congested but the (more expensive) peaking technology is the price setter, the social value of transmission investment is high. Hence to fully grasp the impact of new transmission investment one needs a detailed economic model of the network and of competition between generators. As the Australian power system is turning over its generation fleet (away from base-load), this need for careful modelling is becoming all-the-more pressing.

Third, the social value of transmission investment is not limited to arbitraging prices (or marginal costs of generation) between two markets, or two nodes. It includes the impact of transmission investment on generation investment, and on the intensity of competition between generators. The impact of transmission on investment in generation, again, depends on the pattern of congestion and on which technology is the price setter. If the expensive technology is the price setter, increasing transmission capacity means substituting cheap power for expensive power, or equivalently, allowing market power to be exercised on a larger quantity.

Leautier (2013) studies the value of transmission investment under nodal pricing. It is shown that the standard analysis that equates the marginal value of transmission to the expected price difference is not the correct criterion for long run investments (in transmission). Likewise, the long-run perspective (a.k.a. peak-load pricing), which ignores transmission congestion and whereby the expected price is equal to the short-run marginal cost plus the capital cost, is also incorrect. The reason is that it ignores the cost of congestion. Combining these two elements yield more accurate insights. First, the impact of increasing transmission capacity depends on both the extent of the current congestion, as well as on the substitutability of generation capacity. Second, the marginal value of transmission capacity depends on the current installed transmission capacity. If it is large (little congestion), the marginal value of transmission is exactly the difference in short term marginal costs, plus the difference in investment costs (between the two generation technologies). It the installed transmission capacity is small (large congestion), the marginal value of transmission is larger (intuitively), but always bounded. The conclusion is that the marginal value of transmission capacity may be lower than the expected difference in short-term marginal costs. Hence valuing transmission capacity is also not obvious.

Thus, in short, planning transmission investment requires internalizing its effects on generation investment and on the incentives for generators. Thus bodies like the AER or the AEMO are better placed to conduct this analysis than the TNSP. The reason is that the goal of a TNSP is to maximize its profit, not social welfare. However social welfare *is* the criterion by which to evaluate these investments, the financing of which may take many forms – including pubic intervention if it is socially valuable. We reiterate that introducing LMP is a first important step in collecting useful information on local congestion.

3.2 RIT-Tests for Transmission – (5.15 and 5.16)

In light of the previous comment a RIT-T for TNSP is likely to not be the correct test for at least two reasons. First, such a test should include the externalities transmission investment induces. Second, a more pertinent test should also include an alternative option or possibly a complement, to the proposed transmission investment. These may include generation investment on either side of the congested line, or soon, large-scale storage investment.

Again, Locational Marginal Pricing is the tool to correctly evaluate, at least in part, the benefit of transmission investment.

3.3 Non-network options – (5.22.10)

In the current document *non-network options* are relegated as an afterthought while the implicit priority is given to a network solution. Indeed in Section 5.22.10, first an actionable ISP project (that is a network project) must be identified, and then AEMO must solicit a non-network solution. Non-network solutions, especially in light of the previous comments, should be part of the ISP on equal footing to network solutions.

Non-network options should not be limited to physical investments such as batteries, for example. They should also include simple and cheap instruments like prices. For example, the optimal response to a solar farm increasing its capacity may not be to build more transmission. Instead it may be to design a wholesale market that generates incentives to invest in storage rather than more solar capacity. In this simple scenario, there is no need for more transmission, while the investment can be made and be adequately rewarded.

4 Conclusion

Developing an Integrated System Plan is a useful exercise and a useful planning tool, especially as the NEM transitions from mostly synchronous, base-load generation that is completely predictable, to intermittent, asynchronous (renewable) generation. However much more care must be taken in evaluating the transmission and distribution investment needs.

The regulators must adopt the correct criterion, they must avail themselves as much information as possible, including from the actual market, and they must better understand the subtle relationships between transmission and generation investment decisions, as well as between wholesale prices and generation investments. This requires more technical work, which is fortunately much cheaper to perform than if committing blindly to an investment plan.