PLANNING ENVIRONMENT

Contents:

These are the conditions that defined the planning context for the 2015 IRP.

REGIONAL RESOURCE ADEQUACY

The long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,[1] differ in some details, but most of the forecasts point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus will cross over to deficit at some point in the next decade – unless new resources are developed. Based upon current information, and assuming that all independently owned generation will be available to serve peak PNW loads, the region will transition from a winter peak surplus of 1,975 MW in 2016 to a winter peak deficit of 3,110 MW in 2025.[2]

For more than a decade, the region's surplus has kept wholesale market power and capacity prices low, and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. Currently, PSE relies on more than 1,600 MW of wholesale market purchases to meet winter peak obligations,[3] but now that the planning environment is changing, this strategy needs to be re-evaluated. The financial and physical risks of continuing such a high degree of reliance on wholesale market purchases in deficit conditions are substantial.

Two factors are of particular concern in relying on the wholesale market to meet winter peak power demand: 1) the physical availability of wholesale power; and 2) rising prices as the supplies grow scarcer. Under certain conditions described in the regional forecasts, it is possible that there may not physically be enough energy and capacity available within the Pacific Northwest – even including spot market imports from California – to meet all of the region's winter firm loads. So, one or more PNW load-serving entities would be forced to curtail service to customers. Since PSE is one of the largest – if not *the* largest – purchaser of winter capacity in the region, PSE's customers would be particularly exposed during regional curtailment events, because large portions of the energy and capacity that PSE was counting on to purchase may simply not be available.

1 / The Northwest Power and Conservation Council (NPCC or the Council), the Pacific Northwest Utilities Conference Committee (PNUCC) and the Bonneville Power Administration (BPA). These studies are included in Appendix F, Regional Resource Adequacy Studies.
2 / Based on information provided in PNUCC's 2015 Northwest Regional Forecast and BPA's 2014 Pacific Northwest Loads and Resources Study. The cited figures include firm imports from California, but do not include other short-term imports that may be available. These studies are included in Appendix F, Regional Resource Adequacy Studies.
3 / See Chapter 6, Electric Analysis, for more detail on wholesale market purchases and peak need.

Certain characteristics of the WECC (Western Electricity Coordinating Council) wholesale marketplace also contribute to the risk profile in deficit conditions. Three are particularly important: 1) Many transactions are financially firm but not physically firm; 2) any wholesale power sale is subject to curtailment; and (3) aside from paying liquidated damages, the non-performing party has no obligation to replace the physical supply of power to the buyer, so the buyer must locate and contract for replacement power. Since prices can rise dramatically in times of scarcity and there are many exceptions to the current WECC wholesale market price cap of $1,000 per MWh, PSE could be subject to very high costs to meet load and reserve obligations.

Appendix G, Wholesale Market Risk, discusses the risks associated with the wholesale electric market exposure in more detail.

CONVERGENCE OF GAS AND ELECTRIC MARKETS

The increasing use of natural gas for electric generation has also increased awareness of the need for coordination between the two industries. Both sectors and several government agencies are working to address the growing interdependence and avoid a crisis. Generally, two aspects of the convergence are attracting concern: operational issues and long-term planning.

Operational Issues

The gas and electric markets have different trading days and hours, and this presents significant obstacles to coordination. Gas markets conduct business on a standard nationwide "gas day." Regional electric markets conduct business on a calendar-day basis, and they also operate in hourly and sub-hourly increments. This mismatch between trading days and hours creates challenges for electric generation operators who are trying to line up supply across time zones.

In 2014, FERC published a Notice of Proposed Rulemaking (Docket No. RM14-2), in which it proposed an aggressive set of changes to the timing of the gas day and scheduling of natural gas intended to improve coordination between the gas and electric industries. In response, the two industries came together under the guidance of the NAESB (North American Energy Standards Board) and recommended adoption of an expanded and better-coordinated daily gas nomination schedule and no change to the gas day. While FERC had proposed the change in the gas day in an effort to improve access to gas supplies in certain organized markets, the vast majority of the gas industry participants and many electric generating interests opposed the change. FERC, in its Order No. 809,[4] dated April 16, 2015, adopted the NAESB proposed gas nomination schedule and accepted NAESB's recommendation to leave the gas day unchanged. PSE was actively engaged in the NAESB gas day/gas scheduling process and remains heavily involved in ongoing regional and national efforts to facilitate better gas/electric coordination.

Another operational challenge is the need for gas and electric industries to coordinate communication and actions in emergency situations. PSE has led the effort to address this issue through development of the Northwest Mutual Assistance Agreement (NMAA). The NMAA provides for communication among regional gas utilities and power generators during emergency situations on the gas system, and it tests this capability periodically.

4 / *http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf*

Long-term Planning Challenges

In addition to the conditions outlined in the Regional Resource Adequacy section above, gas-electric convergence issues are also having an impact on long-term resource planning. These have to do with the increasing strain on the gas infrastructure system as higher and higher volumes of natural gas move through it. Two issues in particular cause concern: available pipeline capacity and volatility.

Available Pipeline Capacity. Some power generators and industrial end-users have come to rely upon the availability of less-expensive interruptible[5] pipeline capacity to economically transport gas for generation fuel and industrial process uses. Interruptible capacity has been plentiful for many years, as the market “grew into” the capacity expansion that went into service in 2003. But, as demand increases for natural gas to serve both gas customer growth and electric generation fuel needs, less interruptible pipeline capacity is available. Available pipeline capacity will shrink as a result, and interruptible users may have to make different, and more costly, commitments to firm pipeline capacity in order to maintain reliable service. According to the Northwest Gas Association (NWGA) 2015 Gas Outlook, “under the expected and high demand cases, peak day loads could stress the system, approaching or exceeding the region’s infrastructure capacity within the forecast horizon”.[6] To meet incremental demands, expanded pipeline capacity will be needed in some locations. See Chapter 7, Gas Analysis, for a more detail on PSE’s gas pipeline capacity position.

The Western Interstate Energy Board’s State-Provincial Steering Committee (SPSC) formed the Western Gas-Electric Regional Assessment Task Force to examine this issue across the WECC,[7] and the PNUCC and NWGA have also developed a Power and Natural Gas Planning Task Force to monitor the situation.[8]

5 | Interruptible capacity on a fully-contracted pipeline results from a firm shipper not fully utilizing its firm rights on a given day. This unused (aka: interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day.
6 | http://www.nwga.org/2015-natural-gas-outlook/
7 | Materials from the SPSC’s Task Force are available at http://westernenergyboard.org/natural-gas/study/
8 | Additional information on the PNUCC/NWGA Power and Gas Task Force is available at http://www.pnucc.org/system-planning/power-natural-gas-taskforce

Volatility. The growing use of peaking generation plants that ramp up and down hourly to balance fluctuations in load and intermittent resources presents another challenge. As demand for natural gas to fuel this type of rapid-deployment generation increases, it can create large swings in gas loads on the interstate pipeline system. This has the potential to strain the entire supply chain, including upstream pipeline and processing capacity.

Both of these conditions make the availability of firm gas storage an increasingly important resource to consider when building portfolios.

GAS SUPPLIES AND PRICING

Natural gas supplies continue to exceed expectations due to the abundant supply of natural gas from shale formations and improving production techniques. Although gas supplies have continued to grow, gas supply development has begun to slow in the face of current over-supply, low prices and the dip in oil price. As stated in the NWGA 2015 Gas Outlook, "While natural gas prices will likely continue to be vulnerable to volatility and spikes during periods of very high demand (as was seen during the winter of 2013/14), they are not expected to return to the sustained high price environment of a few years ago." [9]

Long-term projections of natural gas's affordability continue to augment the role of natural gas in our region's environment and economy. Natural gas remains a good economic value as an energy source, especially compared to its price levels of just a few years ago and the price of substitute fuels like oil. This remains true even in the current environment of lower-priced oil.

Pipeline Transportation and Storage

Though the gas transportation system is adequate to meet current demand, it is likely to experience increasing stress as more and more of the region's electric generation requires natural gas for fuel, as liquefied natural gas (LNG) exports materialize, as large industrial uses such as methanol plants are developed, and as the transportation sector[10] begins to adopt natural gas as an attractive fuel option. Significant additions of gas peak loads will certainly require expanded pipeline capacity for certain locations (see Chapter 7, Gas Analysis). Given the scale of new industrial demand it's important to note that large new industrial gas users may have more control over timing and location of future infrastructure expansions than existing users, including utilities.[11]

9 / http://www.nwga.org/wp-content/uploads/2015/06/2015OutlookWEB.pdf
10 / In this context, transportation sector includes maritime and heavy truck shipping and CNG vehicle use.
11 / Northwest Gas Infrastructure Landscape Looking Forward, a paper produced by NWGA and PNUCC, discusses the development of large industrial gas loads. http://www.nwga.org/wp-content/uploads/2015/07/Northwest-gas-inf-FINAL-Jul-2015-v21.pdf

LNG Storage Opportunity. The 2013 IRP included the development of a mid-scale LNG liquefaction and storage facility as an alternative resource to serve the growing demand for LNG as a marine and vehicle transportation fuel. This LNG facility was selected as a cost-effective resource in the 2013 IRP. In this 2015 IRP, we continue to pursue this alternative and find that building a facility that can serve both core gas customers as well as the needs of transportation fuel customers will enable PSE to reduce the cost of the peaking service to core gas customers. This IRP evaluates building an LNG facility that would serve both needs: 1) provide on-site storage capacity to serve gas customers' peak needs; and 2) supply LNG fuel to serve Puget Sound's marine traffic and the natural gas vehicle market.

Gas for the Transportation Sector

While the market share for alternative-fueled vehicles is currently small, PSE has seen a marked increase during the past few years in the number of natural gas vehicles (NGVs) within the utility's service territory. At the end of 2014, there were over 825 natural gas-fueled vehicles registered in the counties where PSE's natural gas customers live. PSE delivered more than 870 thousand dekatherms of natural gas to NGVs in 2014 – equivalent to the natural gas consumption of about 11,000 homes. In addition, interest in LNG fuel for marine transportation is strong and growing.

Demand for natural gas as transportation fuel is expected to increase over time because of its advantages compared to gasoline and diesel fuels: it is less expensive and produces significantly lower carbon dioxide (CO_2) and nitrogen dioxide (NO_2) emissions. In addition, since the transportation sector is the largest contributor to CO_2 emissions in the state, it can also make a significant contribution to meeting state and federal emission reduction targets.

The relative lack of access to refueling stations is likely inhibiting more widespread NGV adoption in Washington. Similarly, the absence of an LNG supply chain in the Puget Sound area may be hindering ship and ferry conversion from high-cost, high-polluting petroleum fuels to natural gas.

Compressed Natural Gas (CNG). In order to assist customers with financial and technical barriers around compressed natural gas, PSE recently developed and obtained regulatory approval for a service to provide customers with compressed natural gas suitable for use in vehicles at the customer's site.

SYSTEM FLEXIBILITY

Balancing reserves and contingency reserves are the two components of PSE's flexibility need.

Balancing Authority Challenges

As a Balancing Authority (BA), PSE must retain enough operational flexibility to keep the system in balance as demand and supply vary from moment to moment. These fluctuations happen continually and are caused by a wide variety of events, from morning demand spikes to the need to compensate for wind generation when winds drop below minimum velocity, and from unplanned generator outages to scheduled energy interchanges. The flexible capacity used to manage this variability is called balancing reserves. In addition to balancing reserves, PSE must also (like other Balancing Authorities) carry capacity that is capable of responding to infrequent but significant regional events (as when a large generator suddenly fails); these are called contingency reserves.

Flexibility needs are met by dispatching resources that can immediately change their output levels to match changes in load or other resources' increase or decrease in generation. Specific characteristics such as how quickly a resource can synchronize to the PSE system, minimum and maximum operating range and ramp rates determine the flexible capacity available from a given resource.

Currently, the company's share of Mid-Columbia hydroelectric assets provides most of PSE's balancing and contingency reserves; however, PSE's share in these assets has declined in recent years due to expiring contracts. PSE now relies on natural gas turbines more frequently for balancing reserves. The move to thermal resources to meet flexibility needs and the increase in intermittent wind generation in PSE's Balancing Authority area impacts both portfolio costs and operations.

Appendix H, Operational Flexibility, discusses the portfolio's ability to effectively balance load and wind fluctuations and describes the related economic analysis.

Energy Imbalance Market

To help address operational flexibility needs, PSE is scheduled to join the voluntary, within-hour Energy Imbalance Market (EIM) operated by the California Independent System Operator (CAISO) effective October 1, 2016.

The current energy market in the Pacific Northwest is structured around hourly energy products traded among entities on a bilateral basis. This structure allows BAs to balance their systems on an hourly, forward-looking basis. But, because there is no liquid market for energy within each operating hour, BAs must rely on their own generating resources within the hour to continuously match changes (or imbalances) in load and generation. To accomplish this, they may have to dispatch a relatively high-cost resource while a neighboring entity has a lower cost resource they would be willing to dispatch if a market were available. Also, the within-hour flexibility needs of all of the region's BAs increases as intermittent resources like wind generate more and more of the region's electricity.

The EIM provides another tool for reliably and economically maintaining balance between electric demand and resource generation. BAs will continue to transact day-ahead and hour-ahead to balance their forecasted load; then, ahead of the operating hour, participating BAs may voluntarily bid their excess generating resources into the market. The EIM Market Operator will integrate all bids into its Security Constrained Economic Dispatch (SCED) software, which will settle and clear on both a 15-minute and a five-minute basis the imbalances across the entire EIM footprint.

By considering the operational needs and available resources from multiple BAs, this market results in lower cost, more efficient dispatch of resources and allows BAs to collectively manage their individual imbalances. From a system flexibility perspective, the EIM can reduce the cost of procuring and deploying flexible resources and potentially reduce the amount of balancing reserves BAs must hold.

ENVIRONMENTAL REGULATION

PSE's generating facilities are subject to a wide range of environmental regulations established by state and federal governments and administered by their agencies. Among the significant Washington state laws are RCW 80.80, which restricts emissions to a level that precludes development of new coal resources in the state, and RCW 70.235.020, which commits the state to reduce greenhouse gas emissions to 1990 levels by 2020. Other environmental regulations that affect PSE operations include:

- Section 111(b) of the Clean Air Act
- Section 111(d) of the Clean Air Act
- Coal Combustion Residuals regulated under the Resource Conservation and Recovery Act
- The Mercury and Air Toxics Standard
- The Clean Water Act
- The Regional Haze Rule (Montana)
- National Ambient Air Quality Standards
- Washington State's Carbon Dioxide Mitigation Program
- Proposed Washington Clean Air Rule.

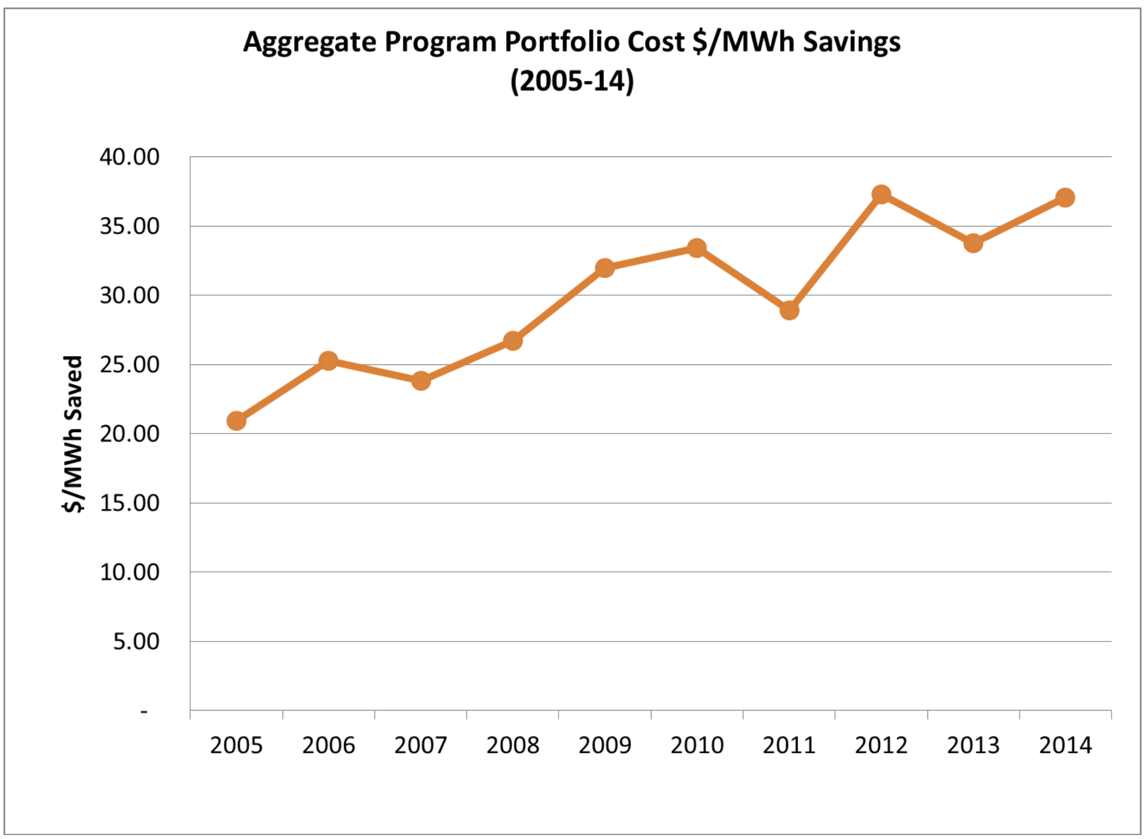
All of these regulations are discussed in more detail in Appendix C, Environmental and Regulatory Matters.

DEMAND-SIDE RESOURCES

While energy efficiency programs are still able to achieve savings targets in the slow-growth aftermath of the financial crisis, a number of shifts and trends specific to the energy industry are affecting how programs are delivered, how information is used to create new programs and the development of delivery networks. Among these shifts and trends are lower natural gas prices, the migration of digital technology and data into energy efficiency applications, rapid improvements in and adoption of LED lighting, the end of the federal energy efficiency credits, new federal appliance standards and changing consumer behavior in energy consumption.

As these shifts are taking place, the cost of acquiring demand-side resources is also rising steadily. Figure 3-1 shows the historical trend. Despite a recent dip, this upward movement is likely to continue because as the “easier,” low-cost measures get captured in earlier cycles, the cost of capturing marginal units of savings increases. Newer technological solutions are often more costly, and inflation also contributes to rising costs.

Figure 3-1: Cost of Demand-side Resources



Declining gas prices combined with the increasing costs are compromising the cost-effectiveness of some program areas, especially for some of the more expensive gas measures. This has led to re-examination of those measures and to the development of new approaches to bringing cost-effective technologies to market. One example is an on-going collaboration with the Northwest Energy Efficiency Alliance (NEEA). Along with other regional utilities, PSE helped to start this gas collaborative, whose goal is to pool resources and use NEEA's expertise in energy efficiency markets to introduce commercially available technologies that hold the promise of significant savings, but that have not yet been adopted in the Pacific Northwest. Such collaborative investments may open markets to new cost-effective gas programs in the future.

RENEWABLE PORTFOLIO STANDARDS (RPS)

Washington state's RPS (RCW 19.285) requires that a specific portion of electricity provided by a utility be from renewable resources; specifically 3 percent of load by 2012, 9 percent by 2016 and 15 percent by 2020. PSE has met the 2012 RPS requirement to provide 3 percent of load with renewable resources and is on track to meet the 2016 and 2020 RPS requirements.

The company's RPS need is expressed in units called renewable energy credits (RECs). To model the RPS need for this IRP, PSE tested how different load levels affected our need for RECs. Additionally, the RPS allows for REC banking within specified time periods. This analysis assumes a REC banking strategy, which pushes the need for RECs later into the planning period relative to not banking. The REC banking strategy used here is a representative strategy, not an official strategy of the company.

The statute that governs RPS requirements also includes a revenue requirement cost cap alternative to acquiring RECs. According to RCW 19.285, all electric utilities in Washington must meet 15 percent of their electric load with eligible renewable resources by 2020. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility shall be considered in compliance with the annual target. Appendix N, Electric Analysis, includes an analysis that demonstrates PSE is expected to remain under the incremental cost cap.

ELECTRIC RESOURCE ACQUISITIONS

The Acquisition Process

The IRP provides a forecast of demand- and supply-side resources that could be used to meet resource needs. When PSE must fill an actual capacity need, it begins an acquisition process in which specific resource decisions must be made in a dynamic environment. In this process, PSE considers the IRP results along with several additional factors. These factors include the actual availability and cost of proposed resources, specific issues related to proposed resources such as the availability of transmission and gas transportation, changing needs and external influences.

A utility can acquire resources in a number of ways: through competitive bids in a request for proposals (RFP) process, by constructing resources, by operating conservation programs or by purchasing power with negotiated contracts.

WAC 480-107-015 outlines the timing of an RFP. Under the WAC, an RFP must be filed if the IRP shows a capacity need within the first three years of the IRP's planning horizon, though PSE can issue an RFP for a need further out than three years. The process unfolds as follows.

PSE issues an RFP to interested parties and posts it on its website. The proposals submitted are evaluated in a two-phase process using these criteria:

- Compatibility with resource need
- Cost minimization
- Risk management
- Public benefits
- Strategic and financial benefits.

Phase 1 screens proposals to eliminate those with high costs, unacceptable risks or feasibility constraints. It uses a quantitative analysis to screen bids and a qualitative analysis to identify fatal flaws. Phase 1 produces a short list of candidates that advance to Phase 2 of the RFP process. In general, proposals on this list have positive economic benefits and no fatal flaws.

Phase 2 is a due diligence process. Input assumptions such as load and gas prices are updated as needed, more extensive quantitative analysis is performed to evaluate resource portfolios using various assumptions, and qualitative analysis is conducted based on the evaluation criteria. Phase 2 produces a list of proposals with the lowest reasonable cost and risk that best meet PSE's identified resource and timing needs.

PSE officers are kept apprised throughout the process, and updates are provided to the company's Energy Management Committee[12] (EMC). When Phase 2 is completed, a short list of proposals is formally recommended to the EMC for approval. PSE then enters negotiations with short-listed counterparties, and if agreements are reached then possible acquisitions are submitted to the EMC and, in some cases, the Board of Directors for approval. If an acquisition is made, PSE requests a prudence determination from the Washington Utilities and Transportation Commission (WUTC) when the company proposes in a rate proceeding to include the new resource's costs in its rate base and revenue requirement.

How Resource Size Is Determined

The capacity and RPS needs are determined in the IRP and updated on an ongoing basis as new information becomes available. The IRP provides a theoretical picture of the future resource portfolio using a range of generic resources that could be used to meet the capacity and RPS needs under different sets of assumptions. The size and cost of each generic resource are based on what is currently available in the market for that type of resource.

An RFP involves evaluating specific proposals submitted by counterparties as well as internally developed proposals for self-build options. In both the IRP and RFP, PSE uses the Portfolio Screening Model (PSM) to optimize PSE's energy portfolio by minimizing total portfolio cost subject to the two constraints of meeting peak capacity need and the RPS requirement. In both the IRP and RFP analyses, new resources are added in blocks to meet load over the 20-year planning horizon, which results in excess capacity when new resources are added. Gradually, this excess capacity decreases as load grows until there is another build requirement driven by peak capacity need. Evaluation of resource alternatives assumes that excess energy and RECs can be sold into the market. A given bid is evaluated based on its impact on total portfolio cost, its ability to meet the capacity and RPS needs, and qualitative factors. Results are re-evaluated as time passes and new information becomes available.

12 / PSE's EMC provides policy-level and strategic direction for the company's energy resource planning, operations, portfolio management and acquisition decisions.

With respect to how large a wind farm should be, PSE must consider multiple factors when deciding how many turbines to install. Factors that influence this decision include:

- **The type and size of turbine.** This impacts the spacing of turbines on the site and the number that can be installed.
- **Geography of the site.** This can dictate how spread out the turbines are, the number of turbines and the amount of infrastructure such as substations, transmission and roads that are required. The equipment is arranged to be as efficient as possible.
- **Schedule.** A short construction period that includes two summers and one winter is preferable to a longer construction period so that the assets can be placed into service as soon as possible.
- **Interconnection agreements.** Transmission requirements can influence the timing and planning for how the work is done.
- **Contracts with counterparties for delivery of materials and construction**. The turbine supply agreement and balance of plant agreements need to be integrated to avoid gaps in the schedule.

A wind farm is planned to be large enough to capture economies of scale while being small enough to have a relatively short construction period. Some of the required infrastructure is the same for a plant ranging from 100 MW to 250 MW, so if the plant is on the larger side, there are economies of scale as fixed costs are spread over greater plant output. Beyond some size threshold, adding turbines would also require additional infrastructure and construction time, thus delaying the in-service date of the assets.