PacifiCorp - Stakeholder Feedback Form

2019 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2019 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 9/7/2018

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Public Meeting Date comments address: **9/27/2018** ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting: Click here to enter text.

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

☐ Check here if any of the following information being submitted is copyrighted or confidential.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

All - WUTC staff intends to file feedback after each IRP meeting to keep the lines of communication open and to signal as soon as possible whether there are any concerns. Below are slide-by-slide comments and questions, working from the hard copy slides provided (117-slide PAC presentation).

A note on process: As most of the participants have acknowledged, the interest of getting good analysis included in the slides has to be balanced with providing lead time with meeting materials. This balance was clearly not achieved in the September meeting, as materials were emailed to the stakeholders at 6:23 p.m. the day before a meeting. If the company takes stakeholder participation seriously and views in-person participation as the most efficient venue for hearing and responding to questions and feedback, the company must provide these materials with the lead time needed for stakeholders to provide useful comments and questions. I encourage the company to distribute meeting materials two full business days prior to the two-day meetings.

My apologies for missing these September meetings. Fortunately, other UTC staff were able to attend, and I talked with them about the proceedings.

I understand that there was a webinar or similar meeting earlier this month involving OPUC that discussed the coal study. I would appreciate a copy of these meeting materials or presentations. Please provide them, or point me in the right direction if these materials are available elsewhere.

PacifiCorp Response:

* Required fields

PacifiCorp held a meeting with Oregon stakeholders October 4, 2018. Presentation materials from that meeting can be located on the Oregon Public Utility Commission's website here: https://apps.puc.state.or.us/edockets/search.asp under Docket LC 70.

Slide 7: Burns and McDonnell's study looks at a generic point within each state for solar and wind. I understand the need for a proxy, but am curious about how this proxy is determined for resources which are so dependent on location.

PacifiCorp Response:

The proxy sites were selected because they are expected to have feasible and favorable characteristics for solar and wind resources within each state. Most of the proxy sites are in areas where wind and solar generation projects have been developed.

Slides 10-11: I'd have expected some non-zero variable costs for pump storage and CAES. Is assuming zero variable costs common for these resources? Also, I believe it was in a previous meeting that we discussed representing Li-Ion storage degradation as a variable cost. How does PAC model these kinds of factors, if not in these resource characteristic inputs?

PacifiCorp Response:

Operations and Maintenance (O&M) costs for compressed air energy storage (CAES) and pumped storage are not broken out into fixed versus variable, they are only shown as a total $/year amount. A component of that cost is variable O&M. Lithium-ion battery (Li-Ion) degradation is covered by an O&M allowance for the addition of cells throughout the project (included in the O&M cost) as well as an initial buildout allowing for space for this needed expansion (included in capital costs).

Slide 13: This conversion factor of 1.32 DC = 1 AC was higher than I would have expected. Please provide some additional background on this conversion factor. What are the factors that go into its calculation? Does this have to do with sizing the panel numbers to about 125% higher than the inverter capacity to keep inverter efficiency up? Would this conversion factor be different from state to state?

PacifiCorp Response:

The Inverter Loading Ratio (ILR) of 1.32 is the ratio at the beginning of the project. As the project degrades in subsequent years (about 0.5% a year) the direct current (DC) output will reduce. The 1.32 initial ILR allows for the alternating current (AC) output to remain constant even after some DC output degradation by reducing this ILR in subsequent years. This will continue to decrease until it is closer to 1.2 towards the end of the project life. 1.2 is considered near industry minimum ILR.

Slide 14: Capital cost estimates are "based on" the B&M assumptions. What else goes into PAC's cost estimates?

PacifiCorp Response:

Capital costs are screening level in nature and are based on top down adjustments to bottom up engineering-procurement-construction (EPC) quality estimates for similar project types, recent competitive EPC bids, budgetary quotes on major equipment, and developer input for CAES and pumped hydro. The base capital costs listed in the supply-side resource table of PacifiCorp's 2019 Integrated Resource Plan (IRP) include owner's costs, allowance for funds used during construction (AFUDC), owner's contingency and escalation (discounted back to mid-2018 dollars) above the base EPC costs.

Slide 15: Based on PAC's experience and available information, is it expected that Li-Ion batteries will cycle once per day? How large of an assumption is this when estimating the total benefit of batteries?

PacifiCorp Response:

The costs and O&M presented at the September 2018 public input meeting represented battery costs assuming one cycle per day. Batteries can be used for a number of applications with a variety of operating profiles. The daily cycling assumption was considered representative for a relative comparison to other technologies. Subsequently, PacifiCorp has separately identified the O&M costs associated with Li-Ion storage equipment degradation and replacement costs as a result of cycling. Because these costs are related to cycling the unit, they can be treated as a variable cost, and no explicit assumption for the number of cycles per day is necessary. The breakout of fixed and variable O&M costs for stand-alone

Li-Ion batteries were provided in the updated supply-side resource table from the November 1, 2018 public input meeting. This allows the IRP modeling to better account for the Li-Ion storage costs based on the modeled dispatch.

Slide 30: Are the duct firing rows here the costs for just duct firing? It seems like the MW nameplate is for just the duct firing component, which is less efficient than a normal CCCT. Why is the heat rate the same for both rows?

PacifiCorp Response:

The chart on slide 30 contained inaccuracies at the time it was presented, it has since been corrected and can be found on PacifiCorp's website here, http://www.pacificorp.com/es/irp/pip.html.

Slide 32: I understand that PAC has moved away from including the intra-hour flexible resource credit. I do not have a strong opinion on this issue, but would encourage the company to include in the IRP some narrative explaining the concept, how and why it was developed, how it was used in the final analysis and why.

PacifiCorp Response:

PacifiCorp plans to discuss the Intra-Hour Flexible Resource Credit in the 2019 IRP.

Slide 38: Looks like you address the intra-hour credit and variable cost piece here a bit. Sounds like work is still being done.
Slide 46: I agree with OPUC staff's position (if I understand it correctly) that a $0 carbon price until 2030 in the base case is tenuous. The acknowledgement letter for PAC's 2017 IRP clearly communicated the expectations of a majority of the WUTC's commissioners. I am unclear on how or why PAC would use a carbon price risk other than the one identified in the acknowledgement letter, but it could be that I am incorrect in thinking that the best way to "incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio" is to use that social cost of carbon forecast as a base case input.

PacifiCorp Response:

As discussed at the October 2018 public input meeting, PacifiCorp plans to assume a 2025 start date for its medium carbon price for its base case assumption. PacifiCorp will also study high gas, high carbon and low gas, no carbon bookend price policy scenarios for all portfolios. In addition, PacifiCorp will run analysis using the social cost of carbon in its portfolio development and selection process.

Slide 51: The previous slide highlights that flexible resources will be more valuable as more solar comes onto the grid. If thermal resources are expected to ramp more and more, this new operation should affect the plants' average heat rate. Is this changing dispatch pattern figured into the fundamentals price staring in month 49? Or is the modeled future dispatch of these plants not significantly different than the historical data used to calculate fundamentals-based power costs?

PacifiCorp Response:

Yes, any dispatch change brought on by a unit's higher heat rate, resulting from a change in mode of operation, would be recognized in the fundamentals staring month 49.

If there are a lot of renewables on the system, a thermal unit may move between its minimum and maximum capacity more often and spend more time running at lower output levels where its heat rate is higher. Thus, over the course of a year, a unit will have a different average heat rate than if it were able to run at maximum capacity any time it is committed. To capture this, a thermal unit's heat rate at minimum capacity is modeled reflecting that the unit is less efficient at lower output levels. With that in place, the average heat rate of a heavily cycled unit, over the year, will incorporate the higher heat rate associated with the unit often running below minimum capacity.

Slide 53: What is driving the flattening of prices at ~2027 and ~2034? This pattern appears in the gas price forwards as well. Is this a boom/bust cycle for gas that percolates into power cost forecasts? What is causing this pattern in the 2019 IRP but didn't cause this pattern in the 2017 IRP?

PacifiCorp Response:

The natural gas price flattening at 2028 and 2035 stems from new Appalachian take-away capacity coming online, which carries over into power prices. Since the 2017 IRP, expectations for associated gas volumes have been revised to "lower for longer," thereby requiring more volumes from Appalachia to meet demand. Associated gas tends to be the cheapest supply source followed by Appalachian. This takeaway capacity brings more low-cost Appalachian gas to market, thereby "flattening" prices.

Slide 61: I'm puzzled by how Segment A both satisfies a transmission customer service request but also is not close to fully subscribed. What was the capacity of this line before this project is completed? How much of the existing capacity is subscribed? Who pays for any unsubscribed capacity?

PacifiCorp Response:

This new transmission line is being built to satisfy a transmission customer's need. Transmission is lumpy and not "right-sized" to exact need. Transmission costs are included in rate base, and any wheeling revenues received through PacifiCorp's formula open access transmission tariff (OATT) rate partially offset these costs. Any unsubscribed capacity would be posted on the Open Access Same Time Information System (OASIS) web site as Available Transmission Capacity (ATC).

Slide 63: $679.2 million / 140 miles = $4.8 million/mi. How does this compare to similar projects?

PacifiCorp Response:

The Gateway West (Segment 2) budget listed on slide 63 encompasses a total project cost including transmission and substation projects. The project costs were competitively bid through an EPC process, and are comparable to the Mona Oquirrh 500 kiloVolt (kv) project completed in 2013.

Slide 67: How does NTTG model its needs? Is PAC intending to move this analysis to a different modeling tool? If so, why?

PacifiCorp Response:

The transmission modeling enhancements described on Slide 68 will be incorporated in PacifiCorp's System Optimizer (SO) model. For more information describing Northern Tier Transmission Group (NTTG) and its regional planning approach and process please see: https://nttg.biz/site/index.php?option=com_content&view=article&id=371:nttg-order-1000-regional-planning-and-cost-allocation-process-2&catid=598&Itemid=200.

Slide 78: I wish I hadn't missed this explanation in person. I do not understand the column labels in this table. It seems like it's taking an average or levelized flexible reserve cost for slivers of the 20 year timeframe. What does this tell us? Are the cost inputs for SO and PAR done on a year-by-year basis such that wind added in 2020 will have a very low reserve cost, and wind added in 2030 will have a much higher cost?

PacifiCorp Response:

The integration costs shown in the table are the average real levelized values over the course of a project's expected life (30 years for wind and 25 for solar). The project online date impacts the integration cost because of the chart shown on slide 77. Slide 77 shows how integration costs are relatively low over the next few years, then increase as system resources become more constrained as a result of retirements, expiring contracts, and load growth. Projects with later start dates don't deliver during the earlier period when integration costs are lower, so the average is higher. The integration cost in any given year is assumed to be the same for all wind output in that year. Note that the values shown are only used in the portfolio development process in the SO model, which doesn't model reserve obligations. In the Planning and Risk model (PaR), the specific regulation reserve requirements for a portfolio are modeled.

Slide 79: I would appreciate a table clarifying when PAC is applying an intra-hour flexibility credit to a case/scenario/sensitivity, and when it is not.

PacifiCorp Response:

PacifiCorp plans to provide, for informational purposes, an Intra-Hour Flexible Resource Credit calculation for each portfolio that addresses the cost impacts of the credit.

* Required fields

Slide 87: Why is the Capacity Contribution study year 2030? Why was it 2020 in the 2017 IRP? What prompted the change that looks out almost a decade into the future? Also, what projects are included in the “planned wind and solar” that is included in the study? I’m looking for an understanding of how likely it is that these planned resources will really be part of the system in 2030. Are all of those projects firm, with executed contracts, clear paths to permitting and interconnection, available transmission, etc? Are any retirements of any coal or other facilities also included in this study?

PacifiCorp Response:

As described at PacifiCorp’s July 2018 public input meeting, the selection of 2030 as the target year for planning reserve margin (PRM) and capacity contribution studies in the 2019 IRP represents an analytical improvement where the year selected captures known significant system events anticipated to impact capacity needs. The target study year of 2030 captures 1500 megawatt (MW) of assumed coal retirements, including the Dave Johnston plant, Naughton, and Jim Bridger 1 (and all other events leading into the year 2030). At the same time, the company added two additional bookend study years to ensure that the PRM level selected for the target year is also sufficient in the near-term (2022) and long-term (2036). Planned wind additions in the PRM studies included 1,150 MW of new Wyoming wind enabled by accelerating the Aeolus-to-Bridger/Anticline transmission line, and repowering 999 MW of existing wind by the end of 2020. Planned solar additions include 987 MW of new solar in Oregon and Utah. All solar projects are executed. All other projects are firm, and either executed or approaching execution. Coal retirement assumptions were presented at the June 2018 public input meeting.

Slide 89: What changes were made to the LOLP shape, or what inputs have moved that have caused a change to the LOLP shape? Why is western solar more valuable for LOLP?

PacifiCorp Response:

Loss of Load Probability (LOLP) is calculated from model outputs, with significant changes driven by the addition of online and planned solar and wind resources since the 2017 IRP analysis, prepared in 2016. The addition of solar resources to PacifiCorp’s portfolio reduces the LOLP during hours of solar generation, so it has the most direct impact on the LOLP applicable to solar resources. Other changes to the analysis included the 2030 target year, reflecting conditions during a period in which the available short-term market resources were expected to be fully used. The 2017 IRP used a 2020 target year, which reflected near-term requirements when existing resources and available short-term market resources exceeded load. In the current analysis market purchases were only allowed up to Front Office Transaction (FOT) limits, rather than transmission import limits. Both of these changes result in a more constrained system that is more susceptible to loss of load events. On the other hand, PacifiCorp reduced the capacity contribution values for solar, demand-side management (DSM), and natural gas to be more in line with the contributions these resources were making during the current peak conditions. This results in the addition of more resources to meet the PRM and fewer loss of load events. These other changes have less impact on the hour-to-hour timing of loss-of-load events, so their impact on solar capacity contributions isn’t clear.

West side solar maintains a higher capacity contribution due to differences in the underlying west side solar shapes. Differentiating factors in west side solar shapes include a slightly later summer generation profile due to being located further west (later sunset) and north (longer summer days) and lower correlation with existing resources due to lower west solar penetration. Higher density construction practices and reduced overheating may also be factors.

Slide 93: Why does east fixed tilt solar outperform east single tracking solar in the early afternoon?

PacifiCorp Response:

The resource profiles shown reflect the existing and planned fixed tilt and tracking solar resources on PacifiCorp’s system. Besides project specific differences, there are some general design tendencies between fixed tilt and tracking resources that may be driving the difference in hourly output. For instance, fixed tilt resources may have a greater “over-build”, with a higher DC to AC ratio (more panels relative to the number of inverters). In late afternoon, more panels could produce more generation when cloud cover is present, though the effect would diminish as the sun begins to set and tracking provides better panel orientation. With regard to the relative capacity contributions, because tracking resources are relatively concentrated in southern Utah, they are more correlated as a result of the same local cloud conditions. To the extent east fixed solar resources are somewhat more dispersed, they may generate more when southern Utah solar output happens to be low. Those hours are also likely to have a higher LOLP under the capacity factor (CF) method due to the reduction in southern Utah solar output.

* Required fields

Slide 95: This is an interesting graph. I appreciate the context. It's surprising to see such a steep slope for PAC's study relative to other studies. I would have guessed that PAC's large service territory might create a locational diversity benefit that would cause that slope to be less steep compared to other utilities, and yet this graph shows that I'm off. What am I not considering? Also, would this line look different for east solar vs west solar?

PacifiCorp Response:

The steepness of the capacity credit slope as presented in the graph is relative to system penetration, and will vary with the system being examined. The steepness of the PacifiCorp slope is in part due to the high starting capacity contribution attributed to the first MW of solar capacity added to the system (close to zero solar penetration). This high starting point reflects differences in PacifiCorp's load profile as well as solar technologies and locations compared to other systems. Also, for the PacifiCorp system, the initial portion of the slope represents the impact of the penetration of existing resources and is simply a straight line between the zero penetration starting point and the capacity contribution with existing and expected solar additions. If this line were further differentiated (e.g., by independently measuring the first half of the existing capacity and then incrementally adding the second half), the first portion of the line would likely present a shallower slope, followed by a correspondingly steeper slope, but arriving at the same point (approximately 24% contribution at roughly 6% penetration). The area under the curve up to this point represents the aggregate capacity contribution of PacifiCorp's existing and expected solar resource additions. If those resources were located in different locations (for instance more in the west), the aggregate contribution would change somewhat. However, the incremental difference between east and west solar is likely small, since they have relatively similar output most of the time (i.e. when the sun is up). The line would likely be slightly higher if there was more west solar in the portfolio, given the CF method indicates a higher contribution for West solar.

Slide 98: What are the planning assumptions for the WUTC-requested WCA model runs? I would greatly appreciate discussing this soon, before the company runs this sensitivity. An analysis was performed for the last IRP, but the assumptions underpinning that analysis did not meet staff's expectations.

PacifiCorp Response:

PacifiCorp will facilitate a meeting to discuss staff's specific recommendations and expectations regarding the West Control Area (WCA) sensitivity.

Slide 101: In the first bullet, what does "consider impacts on system reliability" mean? Is this an LOLP value, an output from PaR? What are the three different price/policy scenarios?

PacifiCorp Response:

PacifiCorp will address this at the December 3-4, 2018 public input meeting. PacifiCorp plans to run its PaR model under the following price-policy scenarios: high gas/high CO_2, medium gas/medium CO_2 (base case) and a low gas/no CO_2. PacifiCorp will also evaluate hourly deterministic results from PaR for some sample years to understand how resources are being used to meet load, spin, non-spin, and regulation requirements. The focus will be on periods where the system is stressed (i.e., peak load days, peak net-load ramp days, etc.).

Slide 103: I'm encouraged to see that PAC is including a portfolio optimized based on a social cost of carbon. The results will only be comparable to other portfolios if the company provides the price and risk outputs for both the SCC carbon assumption and the base case carbon price assumption. Please provide PVRRs for these comparable portfolios with both carbon pricing assumptions. For example, what is the cost for the base case portfolio with a SCC assumed, and what is the cost for the SCC-optimized portfolio with the base case carbon price assumed?

PacifiCorp Response:

PacifiCorp will evaluate top performing portfolios and the portfolio developed under the social cost of carbon assumption (if not already among the top performing portfolios) assuming social cost of carbon inputs to the PaR runs, which will allow for a comparison of results among a case with social cost of carbon assumptions and a case with base carbon price assumptions.

Slide 109: PAC's choice to bundle DSM measures by $10 is perplexing. I appreciate that the model cannot handle the optimized selection of each DSM measure for each state, and hence that bundling is necessary. However, I have not been given a satisfactory reason for why PAC thinks the same $10/bundle granularity is needed in the $100s. I strongly encourage the company to apply more granularity where it is useful – in the $20-70 range. Deciding not to provide granularity where it is needed means the model will either leave cost-effective conservation un-selected, or select some bundled measures which are not cost-effective – either of which means the company risks running afoul of their obligation to pursue all cost-effective conservation in Washington.

PacifiCorp Response:

The choice to use 27 cost bundles was made after the 2011 IRP based on stakeholder comments and suggestions that the nine cost bundles that were used in the previous IRPs were not granular enough. PacifiCorp determined that cost levels should be kept as granular as possible up to and slightly beyond the cost levels possible in extreme scenarios. PacifiCorp had to determine a reasonable level to group the measures to model Energy Efficiency (EE). To clarify, there is no bundling of measures when PacifiCorp pursues cost effective EE.

Slide 109: I am not clear on how a point price and the load shape is determined for each bundle. Is the price point a weighted average based on conservation potential and price for each bundle? Is it simply the mid-point of each $10 bundle?

PacifiCorp Response:

Load shapes and levelized costs for each bundle are calculated based on the savings of all measures within a bundle, based on the 20-year sum of incremental potential for each measure. Consider a hypothetical scenario where Measure A provides 75% of the 20-year savings within a bundle at a levelized cost of $42/megawatt hour (MWh) and Measure B provides 25% with a levelized cost of $48/MWh. The weighted-average levelized cost would be $43.50/MWh, weighted towards the measure with higher potential. Cost-bundle load shapes are created in the same way. Using the hypothetical example above, if Measure A is a cooling measure and Measure B is a lighting measure, the load shape would incorporate 75% of the cooling shape and 25% of the lighting shape. The table below highlights this example.

Measure	Savings	LCOE ($/MWh)	Load Shape
Measure A	75 MWh (75%)	$42/MWh	Cooling
Measure B	25 MWh (25%)	$48/MWh	Interior Lighting
Composite Shape	**100 MWh (100%)**	75%*42+25%*48 = **$43.5/MWh**	**75% Cooling + 25% Interior Lighting**

PacifiCorp creates bundles using the levelized cost of the measure. Measures with similar levelized costs are grouped together in "cost bundles". PacifiCorp has state-specific load shapes by end use and sector. These state-specific load shapes are then used to create a weighted average load shape for each cost bundle based on the individual measure mix of each bundle.

Slide 111: What is a project adder?

PacifiCorp Response:

The project adder is an Oregon-specific measure that accounts for large projects that the Energy Trust of Oregon did not account for in the potential. This measure was created to help align the potential analysis with actual program achievements. The project adder measure was not added to other states because the potential for other states incorporated measures for PacifiCorp's large projects.

Slide 113: My point about bundle granularity is evidenced somewhat in this slide. If the levelized cost is $40, the estimated technical achievable potential is about 4 million MWh. If it's closer to $45, the potential is closer to 4.5 million. Half a million MWh in the 'noise' of the bundles is a lot of potential savings to gloss over.

PacifiCorp Response:

The model picks well above these cost bundle levels. If PacifiCorp had different bundle levels, the achievable potential would have to be run, but it is not reasonable to assume that a levelized cost of $45 would result in a .5 million increase in potential MW.

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Slide 114 shows that bundles $100-10,000 represent 17 bundles in the model, but represent about as much potential savings as the three bundles $30-50. Why is this modeling approach preferred?

PacifiCorp Response:

Please refer to PacifiCorp's response to the question regarding slide 109.

Data Support: If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.

PacifiCorp Response:

During the IRP public input process, PacifiCorp has agreed to incorporate feedback received from stakeholders on the Conservation Potential Assessment (CPA) bundles and to run a portfolio that includes bundles based on capacity contribution (P-23). PacifiCorp has finalized the CPA bundles for the 2019 IRP at this time. PacifiCorp may consider Washington Utilities and Transmission Commission Staff's recommendation for future IRPs.

Please change the DSM bundling to provide more granularity where the the marginal cost-effective DSM bundle is likely to be. I would guess that this is in the $30-60 range. An illustration of how this might be implemented is in the table below.

Current DSM cost bundles	Proposed DSM cost bundles
<= 10	<=20
10-20	20-25
20-30	25-30
30-40	30-32
40-50	32-34
50-60	34-36
60-70	36-38
70-80	40-42
80-90	42-44
90-100	44-46
100-110	46-48
110-120	48-50
120-130	50-52
130-140	52-54
140-150	54-56
150-160	56-58
160-170	58-60
170-180	60-62
180-190	62-64
190-200	64-66
200-250	66-68
250-300	68-70
300-400	70-80
400-500	80-100
500-750	100-200
750-1000	200-500
>1000	>500

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☐	Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

Thank you for participating.

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