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U.S. Patent Nos.: 6,470,696, 6,834,509, 6,886,351, 7,798,159, 8,002,897
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The Basics of Horizontal Air Sparge Well Performance Through Idealized Examples

Understanding Distributed Compressible Fluid Transport Using Horizontal Wells

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To best provide the reader with a *general guidance* as to how to anticipate the *possible* (but not yet assured) performance of horizontal air sparge wells, several idealized examples will be presented. For this, and subsequent examples, instead of attempting to explain the engineering and physics involved with designing a horizontal well to achieve any specific purpose (as a future technical treatise will address), a reverse approach will be used. That is, cases will be presented using a horizontal air sparge well that is *already designed* and that well design will be employed under different sets of conditions, to establish *qualitatively* how it will perform. In each case, the reader is well advised to continually bear in mind that the best case performance scenario is presented. With this presentation method, a more intuitive (or holistic, if that term is preferred), rather than analytic, approach will be employed to assist the reader in learning how distributive compressible fluid transport 'works'. Thereafter, it will then be discussed how the initial design *can be changed* to account for *and counteract* the new conditions applied to it, if indeed this result can be achieved.

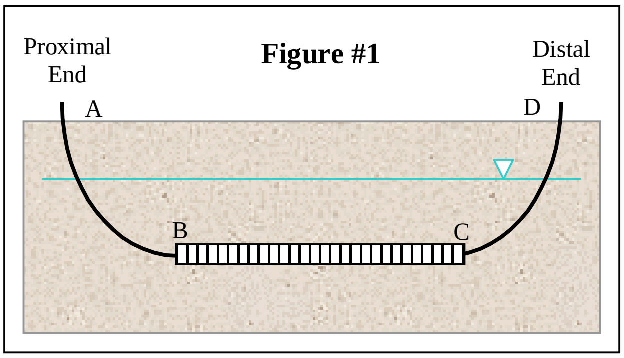
Before proceeding one very important caveat and further explanation needs mentioning:

Compressible fluid dynamics can be, and frequently is, very non-intuitive even for those considered 'expert' in the subject. Because so many physical variable degrees of freedom, or dimensions, are involved, it is extremely difficult to mentally consider all impacting variables concurrently, which must be done to properly formulate a correct and accurate performance conclusion. As the well/system and the conditions of installation become more complex, the ensuing mental juxtaposition of all information becomes even more difficult. Depending on the reader's level of knowledge and experience, it may be quite possible, and even likely, that the well/system will operate exactly opposite of that thought and expected. However, regardless of belief, expectation or intuition, the well/system will always operate in accordance with the Laws of Newtonian Physics.

As each example is discussed, it is additionally *as important* to establish or *define* the baseline set of conditions, which will be applied to that specific example. It can be recalled, by Newtonian Physics principles, each physical system will operate *uniquely* according to the specific set of conditions applied or in effect for that system. Change any one or more of these (many) conditions, and the system will operate differently, and this operation will be *unique* from all other sets of conditions. The conditions applied to each of the ensuing examples, and any changes made thereafter, will be clearly stated so as to highlight them.

A. Baseline Case - A Simplified Horizontal AS Well

In this first example consider a horizontal well as depicted in Figure #1 of nominal 4" diameter SDR-11 HDPE installed perfectly horizontally in homogeneous soil with air permeabilities, horizontal and vertical, equal and equivalent to that of coarse sand. Suppose the well possesses a uniform propagation of slots over its entire 400 ft. long screened interval, these slots resulting in an open well area of approximately 2% [1]. Finally, the well is positioned under 10-feet of groundwater and 10 psig is applied to the well's header. How will the well perform in steady state?



To aid the reader, the "key" design, installation and operating condition constraints will be listed:

- The well is installed perfectly horizontal,
- Hydrostatic head of groundwater is uniform over the well's entire slotted section,
- The well screen is slotted uniformly with an open area of 2%,
- The well screen is 400 ft. long and is fabricated of 4" SDR-11 HDPE material,
- The soil is homogeneous coarse sand, and
- A header pressure of 10 psig is applied (at Point "A" in Figure #1).

The following describes the best possible performance of which this well/system is capable:

Since the static height of ground water above the screen is 10 feet, 4.33 psig of exterior hydrostatic head pressure is present along its *full length.* Since 10 psig (24.7 psia) of pressure is applied to the header, and given that friction losses will exist in the header (prior to the first set of slots), the pressure at the first set of slots, point "B", will be *less than* 10 psig, but *greater than* 4.33 psig. Therefore, some sparge air flow will be present at the first series of slots.

Since the entrance header "sees" the entire volume of sparge air for the entire well, friction losses in this section will be *incrementally greater than* in any other portion of the well. As air escapes from the well screen along its length, the velocity of air remaining inside the well *steadily decreases*. Since the velocity *decreases,* friction losses similarly *decrease.* The in-well velocity at the end of the screened section, point "C" is *zero*, as it is at point "D", the well's distal end.

[1] Percent open area (hereinafter % OA) is *defined* as the ratio of the actual inside surface slot area to the overall inside surface area of the well per unit length expressed as a percent. Thus, if well material is slotted such that 5

However, as air escapes from successive series of slots, the pressure *inside* the well steadily *decreases* along its length. The in-well pressure is the *greatest* at point "A" and is the *least* at point "C". The pressure at point "D" is *identical* to that at point "C". Though we may desire this latter pressure to be high, there is insufficient information to conclude what its value may be.

Since the flow resistance presented by the soil *and* groundwater is uniform over the well's length, this decreasing internal well pressure results in *less* incremental air being sparged with increased distance. Further, this decreasing pressure results in *decreasing* mass density of the air within the well. Thus, not only does less incremental *volume* (and mass) of air exit the screen with distance, the volume that does escape is increasingly *less dense*.

The net result is that the greatest volume (and mass) of air is sparged at the first series of slots, these being exposed to the greatest pressure inside the well. This "first slot" pressure will not and can not be equal to 10 psig, since friction inside the header will reduce it from this initial value. Volumetric sparge air flow with ensuing series of screen slots will become increasingly less with distance. Since internal friction and sparge air loss results in less well pressure with distance, the mass of air sparged decreases as well, being the least at the last slots.

Not yet knowing if air is indeed sparged from the last series of slots <u>but presuming so as the 'best case scenario'</u>, Figure #1 may be annotated with an overlaying graphical representation illustrating the mass per unit length exiting each series of slots. This relative mass flow representation is in vector form with increased height of any one vector meant to indicate that more mass is exiting this area than in adjacent areas. Conversely, less flow is indicated by a shortened height of the respective vector. The completed, enlarged representation is provided as Figure #2.

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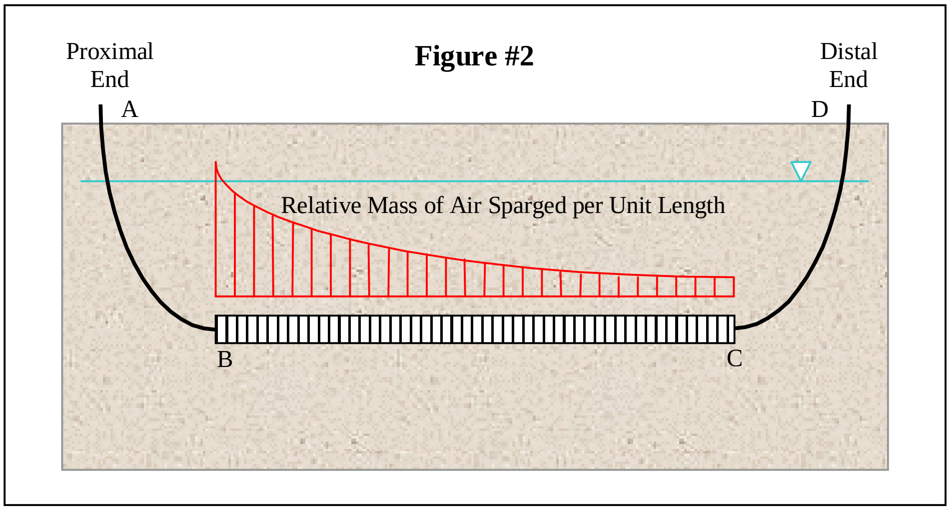
square inch of area per foot of length is exposed on the inside surface and the overall inside surface perimeter area is 150 square inches per foot, the % OA is 3.33%.



Several observations can be made from Figure #2. In reviewing these observations, the reader is once again reminded that for this case studied, sparge air flow was presumed to exist at the last series of slots (however, in practice this is definitely not guaranteed!):

1. The *greatest* mass of air sparged is at the first set of slots, the *least* at the last set of slots.
2. The per unit length *distribution* of sparge air is not uniform over the well's screened interval (e.g., discharge *skew* exists),
3. The *attenuation* of per unit length sparge air flow is not linear but rather is parabolic or *hyperbolic* in nature,
4. The *attenuation* rate decreases with increased distance along the well screen and appears to approach an *asymptote* of some *finite* minimum flow.

B. Case #2 - The Effects Resulting from Increasing Well Header Pressure

Once a horizontal air sparge well is found to exhibit the discharge characteristics described in the baseline case (as it must for the conditions given), it is common industry practice to attempt to "offset" the sparge air skew by increasing the pressure applied to the well's header. The "theory", if it can be called that, is that increasing the header pressure will result in an increased in-well pressure all along the well's length. This increase in pressure will result in much greater pressures away from the well's proximal end leading to greater sparge air discharge at the well's far end. Thus the "theory" and Industry belief is that increasing the applied pressure to a well that already exhibits flow skew will yield the following results:

1. The existing flow discharge at the first set of slots will remain as previously experienced, that is, the increase in header pressure will not change the rate of sparge air flowing from these slots,
2. The pressure along the well will not exhibit the attenuation as previously seen, and in fact if the correct header pressure is chosen, the pressure all along the well screen will become uniform,
3. Since the in-well pressure will become uniform, sparge air flow along the screen will likewise become uniform, and
4. Skew will be eliminated.

Let's examine the validity of this "theory". The reader is once again referred back to Figure #1 since this figure still applies to this revised set of conditions. The only difference between the baseline case conditions listed in bulletized form adjacent to Figure #1 and the new set of conditions is that the header pressure is increased. For illustrative purposes, let us assume the header pressure is increased to 15 psig (29.7 psia) from its initial value of 10 psig.

The analysis of well performance for this second set of conditions follows the exact same process that was used for the baseline case. The following describes the best possible performance of which this well/system is capable:

Header and first slot in-well pressures will be greater than the hydrostatic head of groundwater, so sparge air flow from the first set of slots will exist. Since the header pressure has *increased*, arguably so have the *total* volumetric and mass flow rates of air inside the well. Since this *total* flow will exist in the header, and *friction losses* are a function of the *square* of velocity of this air (refer to the Darcy-Weisbach Equation), the magnitude of pressure loss in the header will be *greater* than that experienced with the previous, lesser header pressure.

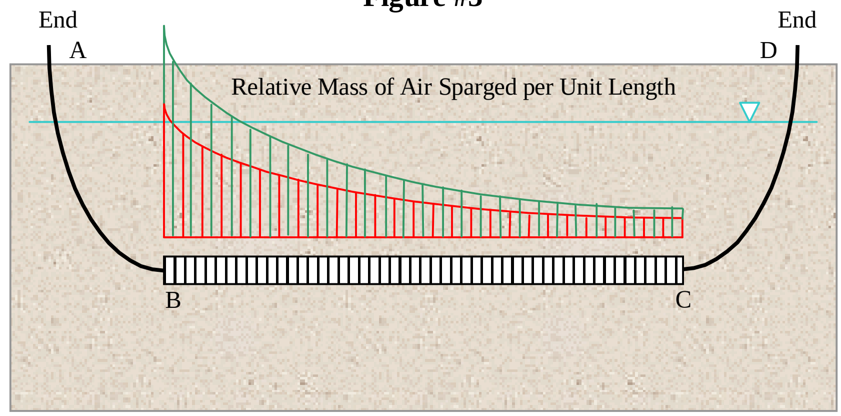
Although friction losses in the header will be present and greater than previously experienced, the pressure at the first series of screen slots will be *greater* than that in the baseline case. However, this first-slot pressure will not be increased by the difference between the two header pressures (that is, the pressure rise from the baseline case will not be 15 psig - 10 psig or 5 psig). This increased pressure gives rise to a comparative *increase* in the volume of air sparged at the first series of slots. Further, the increased in-well pressure at this point results in an *increased* density of the air. Thus, not only will the volume of air sparged at the first slots *increase*, its density and therefore *mass* of air sparged *increases* as well.

As volume and mass of air are discharged (giving rise to in-well pressure reductions), and as friction losses further reduces in-well pressures, the volume and mass of air being sparged from successive series of slots *decreases* with distance along the well screen. Further, since in-well velocities are *greater* along each screen segment, the magnitude of friction loss is *greater* for any segment than that experienced in the baseline case. Thus, the attenuation of in-well pressure along the well *increases* not decreases, from that in the baseline case.

In that in the baseline case it was *presumed* (but again, this is not assured) that sparge air flow did exist at the last series of slots, and if so, it will exist at these same slots for the condition of a greater header pressure. However, as previously described, even with this greater header pressure, the attenuation of pressure all along the well screen will be *greater* than that previously experienced. The net result is that the pressure at the last series of slots will be *greater* than previously experienced, but minimally so. Thus, though the pressure will be greater and similarly volumetric (and mass) flow will similarly be *greater*, the magnitude of this increase will be modest at best. Sparge air skew will not only still be present under this new set of operating conditions, it will be worse than that in the baseline case.

Figure #3 is provided to illustrate the resulting performance of the well by increasing its header pressure. For comparative purposes, the overlaid graphical representation of the mass per unit length exiting each series of slots for the baseline condition will remain in red, while that for the new condition will be shown in green. Since they are concurrently plotted against the same axes, a scale of comparison of relative performance, both overall and incrementally, can easily be visualized.

Figure #3



With this graphical comparison of incremental sparge air flow and the points identified in the previous discussion, the following conclusions can be drawn:

1. Increasing an air sparge well's header pressure *increases* the overall *total* flow rate (volumetric and mass) of the well *and* the rate of exiting air flow from the first series of slots,
2. *In general*, the rate of flow exiting successive series of slots is *greater* at the elevated header pressure than before, but the magnitude of the flow increase becomes *ever-less* with distance,
3. The degradation in per unit length flow discharge is *greater* over the full length of the well. Skew *increases* rather than *decreases*.
4. Though the overall throughput of the well is *greater* than before, the magnitude of increased flow discharged at the last series of slots is *small*.
5. Increasing header pressure does *not* result in more uniform flow discharge over the well's length. Rather, increasing header pressure makes it *worse*.

C. Case #3 - The Effects Resulting from Using High Per Cent Open Area Well Screen

Another technique used in the Environmental Industry to increase the design flow from a horizontal air sparge well is to re-specify a well which may be operating as desired to that of a well with greater (and sometimes much greater) % OA. The prevailing "theory" with this technique is that if a given well with a given % OA (such as our case #1 well at 2% OA) is working acceptably, then an identical well of say, 10% OA would yield 5 times the total flow (10% ÷ 2% = 5), and the distribution of the total flow would mimic that of the original design. Thus the "theory" and Industry belief is that increasing the % OA of a well that already exhibits a known total flow rate and flow distribution will yield the following results:

1. The total flow of the well will increase by a value of the ratio of the two % OA values,
2. Incremental flow discharged from each series of slots along the entire well will increase, the magnitude of the volumetric (and mass) flow rate increase for all slots will be identical to the % OA ratio,
3. The skew that the well exhibits will remain the same, and
4. Flow discharge from the last series of slots is guaranteed.

Let's examine the validity of this "theory". The reader is once again referred back to Figure #1 since this figure still applies to this revised set of conditions. The only difference between the baseline case conditions listed in bulletized form adjacent to Figure #1 and the new set of conditions is that the well possesses more % OA. For illustrative purposes let us assume the new % OA is 10%, five times greater than the well analyzed in the baseline case. The applied header pressure, increased for the discussion of case #2, is returned to its initial value of 10 psig (24.7 psia).

The analysis of well performance for this third set of conditions again follows the exact same process that was used for the baseline case. The following describes the best possible performance of which this well/system is capable:

Header and first slot in-well pressures will be greater than the hydrostatic head of groundwater, so sparge air flow from the first set of slots will exist. Since the well's open area has *increased* dramatically arguably so have the *total* volumetric and mass flow rates of air inside the well. Since this *total* flow will exist in the header, and *friction losses* are a function of the *square* of velocity of this air (refer back to the Darcy-Weisbach Equation), the magnitude of pressure loss in the header will be *far greater* than that experienced in any of the previous cases.

Though it remains unknown to what level the total flow throughput of the well may rise [2] it may be reasonable to assume for discussion purposes that the total flow will be 3 times that experienced in the baseline case. Under this presumption, the increase in flow volume results in a similar increase in header flow velocity and an *extremely* large friction loss in the header. This loss will be 9 <u>times</u> (e.g., $|3 \div 1|^2$) that as experienced in the baseline case, and results in the in-well pressure at the first series of slots being the *lowest* for the cases discussed so far.

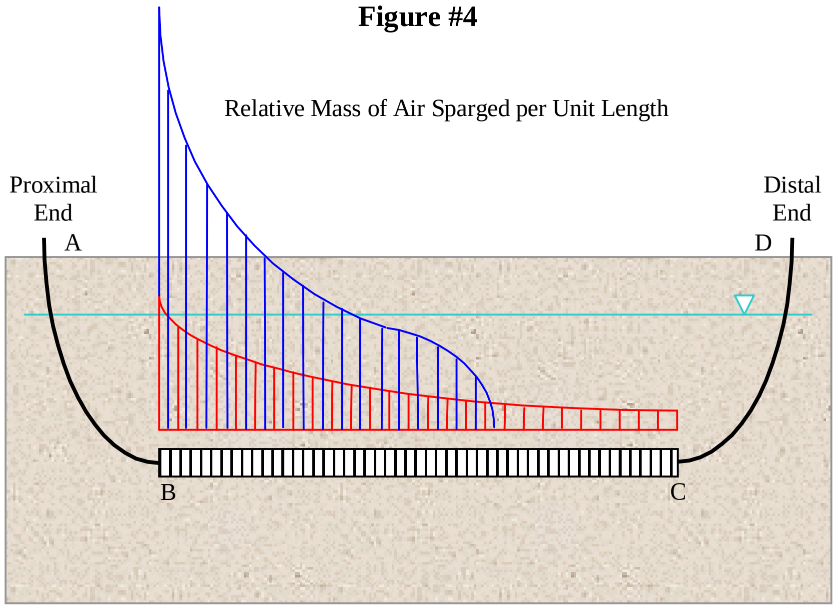
Though the "first slot" in-well pressure is lower than anticipated, the 5-fold increase in open area results in an *extreme* increase in the volume of air discharged from these series of slots. The lesser in-well pressure reduces the density of this air somewhat but the increase in volumetric flow far overshadows this effect, resulting in a *very high* mass discharge flow rate.

The remaining air in the well travels to the next series of slots, but since the in-well velocity is still very large, friction losses along the well screen with distance are *very* high. Therefore, with ensuing series of slots, in-well pressures *drop* dramatically over a *very* short distance, while the volumetric rate of discharge through these slots is *very* high. As before, the volume of flow discharge attenuates with distance along the well screen, however the attenuation for this case is *extreme* and very pronounced. At 65% of the distance along the well screen, the in-well pressure has deteriorated to 4.33 psig, the exact hydrostatic head pressure of the surrounding groundwater. No sparging can exist beyond this point, the remaining 35% of well screen, 140 ft., is benign.

Figure #4 is provided to illustrate the resulting performance of the well by increasing its % OA. For comparative purposes the overlaid graphical representation of the mass per unit length exiting each series of slots for the baseline condition will remain in red, while that for the new condition will be shown in blue. Since they are concurrently plotted against the same axes, a scale of comparison of relative performance, both overall and incrementally, can easily be visualized.

[2] The quantity of total flow in the well being discussed will <u>not</u> equal that of the baseline case well times the ratio of increase in % OA, so total flow cannot rise by a factor of 5, but may under certain circumstances approach this value. Well flow increase by % OA change is <u>not</u> a unitary function.

Figure #4



With this graphical comparison of incremental sparge air flow and the points identified in the previous discussion, the following conclusions can be drawn:

1. Increasing an air sparge well's % OA *increases* the overall *total* flow rate (volumetric and mass) of the well *and* the rate of exiting air flow from the first series of slots,
2. *In general*, the rate of flow exiting successive series of slots is *greater*, but the magnitude of per unit length flow increase becomes *ever-less* with distance due to the degradation of in-well pressure from *friction* and discharge *mass loss*,
3. Skew *increases* rather than *decreases*, and in cases where the increase in % OA is excessive and results in sufficient friction and mass loss to lower the in-well pressure to groundwater hydrostatic head, skew can approach and even equal 100%.
4. Though the overall throughput of the well is *greater* than before, there is a great chance of producing the effect where latter sections of the well may *not* sparge air and/or where sparging air from distal sections of well screen is not possible under any circumstances,
5. Increasing well screen % OA does *not* result in more uniform flow discharge over the well's length. Rather, doing so makes it *worse*.

D. Case #4 - The Effects Resulting from Reducing Well and Well Screen Diameter

For this next case, again as commonly done in the Environmental Industry, a well design that has been found to operate acceptably under a certain set of installation and operating conditions will be modified and made less costly by reducing its diameter. The "theory" is that if an existing well of a certain diameter (such as our baseline case well of nominal 4" SDR-11HDPE material) operates acceptably, reducing its diameter would <u>not</u> affect performance, but <u>will</u> reduce material cost. Since well material is sold on a per-foot basis, and the cost per foot is based (at least partly) upon the weight of the material (and hence mass of HDPE per foot), the "theory" is that reducing well material size will yield the following results:

1. The total flow of the well will <u>remain the same</u> as the original well,
2. In-well pressure and incremental flow discharged from each series of slots along the entire length of well screen will <u>remain the same</u> as the original well,
3. The skew that the well exhibits will remain the <u>same</u>, and
4. Flow discharge from the last series of slots is <u>guaranteed</u>.

Let's examine the validity of this "theory". The reader is once again referred back to Figure #1, since this figure still applies to this revised set of conditions. The only difference between the baseline case conditions listed in bulletized form adjacent to Figure #1 and the new set of conditions is that the well is fabricated of smaller diameter material. For illustrative purposes, let us assume the new well is fabricated of 2" SDR-11 HDPE [3], approximately half the diameter of the well analyzed in the baseline case. The well's % OA, increased for the discussion of case #3, is returned to its initial value of 2%.

The analysis of well performance for this fourth set of conditions again follows the <u>exact same process</u> that was used for the baseline case. The following describes the <u>best possible performance</u> of which this well/system is capable:

From vendor literature [4] 4" SDR-11 HDPE pipe has a nominal inside diameter of 3.649", while 2" SDR-11 HDPE pipe has a nominal inside diameter of 1.926". While 2% open area in the 4" well results in an "absolute open area" (e.g., accrued slot area) of 2.75 in^2 per foot (e.g., 3.649" x π x 12" x .02 = 2.75 in^2) reducing well size proportionally reduces the absolute open area available to sparge air. This reduction is by the ratio of the wells' diameters. Thus, the smaller 2" well will have an absolute open area of 1.45 in^2 rather than 2.75 in^2, or 47% <u>less</u> than the 4" well. Its <u>percent</u> open area will remain at 2%, the same as the 4" well.

[3] The choice of 2" SDR-11 HDPE (to replace 4" SDR-11 HDPE) is used in this analysis as it has been found from the author's experience that this substitution is prevalent in the Environmental Industry.
[4] CSR PolyPipe *Design & Engineering Guide for Polyethylene Pipe*

Header and first slot in-well pressures will be greater than the hydrostatic head of groundwater, so sparge air flow from the first set of slots will exist. Since the well's absolute open area has *decreased* significantly, arguably so have the *total* volumetric and mass flow rates of air inside the well. However, with this reduction in total flow, the cross-sectional area of the new well available to convey this flow has *decreased* even greater. Since available cross-sectional area is a function of the square of the well's inside diameter, the change to the 2" well material reduces the available cross-sectional area in the well to 28% of that in the 4" well. Thus, the reduction in well diameter significantly *reduces* total volumetric and mass flow, it also *reduces* the available cross-sectional area of the well even greater. Header flow velocity will be *quite high* as the reduction in cross-sectional area will more than compensate for the effects of reduced flow volume. Since this *total* flow will exist in the header and *friction losses* are a function of the *square* of velocity of this air (again, refer back to the Darcy-Weisbach Equation) [5], the magnitude of pressure loss in the header will be *very high.*

Though it remains unknown to what level the total flow throughput of the well may be, [6] it is reasonable to assume for discussion purposes that the total flow may approach, but be no greater than, 50% of that experienced in the baseline case. Under this presumption, this decrease in flow volume, offset by the reduction in well ID area, results in an *increase* in header flow velocity and large friction losses in the header.

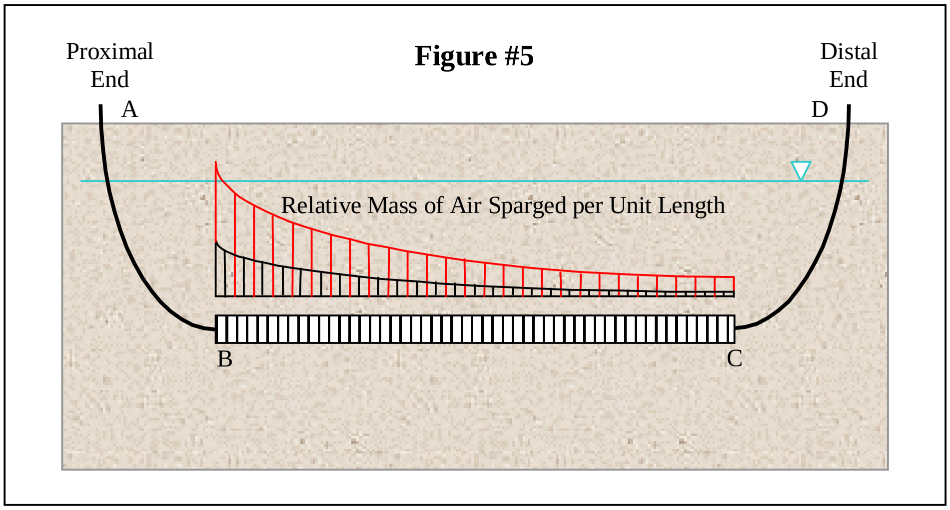
Because the available absolute open area in the first series of slots is quite small, the resulting volume and mass of the air sparged is similarly small. Since little volume is discharged, the decrease in in-well pressure to the next series of slots (due to mass loss) is slight, though pressure losses due to friction dominate. With ensuing series of slots, the effects of friction diminish such that the in-well pressure for latter portions of the well will be *less* than that experienced in the baseline case well.

Sparge air flow for the entire well is thus dominated by the effects of little absolute open area per-foot and friction losses.

Figure #5 is provided to illustrate the resulting performance of the well by decreasing its diameter. For comparative purposes the overlaid graphical representation of the mass per unit length exiting each series of slots for the baseline condition will remain in red, while that for the new condition will be shown in black. Since they are concurrently plotted against the same axes, a scale of comparison of relative performance, both overall and incrementally, can easily be visualized.

[5] Friction loss is also a function of the ratio of inside pipe diameters to the 5th power! This will be discussed in a future section of an in-depth engineering compressible distributed flow fluid dynamics treatise.

[6] Similarly, the quantity of total flow in the well being discussed will not equal that of the baseline case well reduced by the ratio of absolute per-foot open areas. Total flow reduction will not be 47%, but will, with increased friction loss, be greater than this value.



With this graphical comparison of incremental sparge air flow and the points identified in the previous discussion, the following conclusions can be drawn:

1. Decreasing an air sparge well's diameter while maintaining the same % OA *decreases* the overall *total* flow rate (volumetric and mass) of the well *and* the rate of exiting air flow from the first series of slots,
2. The rate of flow exiting successive series of slots is *less* due to the reduction in per-foot absolute open area, and becomes *ever-less* with distance, as in-well pressure *rapidly* degrades due to *friction*,
3. Skew remains approximately the *same* rather than *decreases*, and in fact may *increase*. In cases where the decrease in well diameter is excessive and results in sufficient friction to lower the in-well pressure to groundwater hydrostatic head, skew can approach and even equal 100%.
4. Though the overall throughput of the well is *less* than before, there is a <u>great</u> chance of producing the effect where latter sections of the well may *not* sparge air and/or where sparging air from distal sections of well screen is <u>not</u> possible under <u>any</u> circumstances,
5. Decreasing well screen diameter *does* result in more *uniform* flow discharge over the well's length, however the volume and mass of air incrementally sparged is *less* and in extreme cases may be *extremely* small.

E. Summary

To best compare system performance resulting from each of the three changes that were made to the baseline case well Figure #6 is provided. For this final comparison, the baseline case well performance is included as is our other case examples, and for each well, including the baseline case, the maximum value of air flow mass discharged at the first and last series of slots is annotated against a common datum scale. These maximum values are shown in the color used to depict the performance for that case in the previous Figures. Thus, these annotations may be helpful in comparing and quantifying in relative terms one case against another, rather than simply to the baseline. Finally, since the performance of the case #3 well precluded flow from reaching the distal end of the well, the point where sparging ceases is annotated as a vertical arrow.

Using Figure #6, some comparative generalized conclusions may be drawn. The first and most significant conclusion is that altering any one of the many design parameters in any well yields *dramatic* changes in total and incremental well and system performance. These changes may be in total, first slot or last slot flow rate volumes, skew, or even precluding the possibility of flow being able to be discharged to the well's end.

The second significant conclusion is that if a "baseline" well and system yields non-uniform flow (e.g., skew exists), and uniformity of flow is the desired goal, increasing well head pressure and/or well screen % OA makes matters *worse* rather than better. In the extreme case, as in our case #3, skew reached 100%.

Thirdly, decreasing a well's diameter while maintaining a fixed % OA *greatly decreases* the actual absolute open area of the well screen by *the square of the ratio of its inside diameter to that of the baseline well*, and as a result, overall and per-foot flow is *greatly* reduced. However, accompanying this resultant reduction in overall and per-foot flow is a large *reduction* in skew.

In general terms therefore, where one change results in a performance trait that is desirable, it may be accompanied by one or more traits that <u>are</u> undesirable. Focusing on only one aspect of well-system performance while making (or contemplating) one or more design changes is a very risky proposition at best. For after analysis and review of these four illustrative and admittedly simplistic examples, the reader may have found that what was *assumed* to occur was in actuality not the case. Thus, if executed in the field with the narrow focus and expectation of successful results, the remediation practitioner will be <u>extremely</u> disappointed, as will be his client.

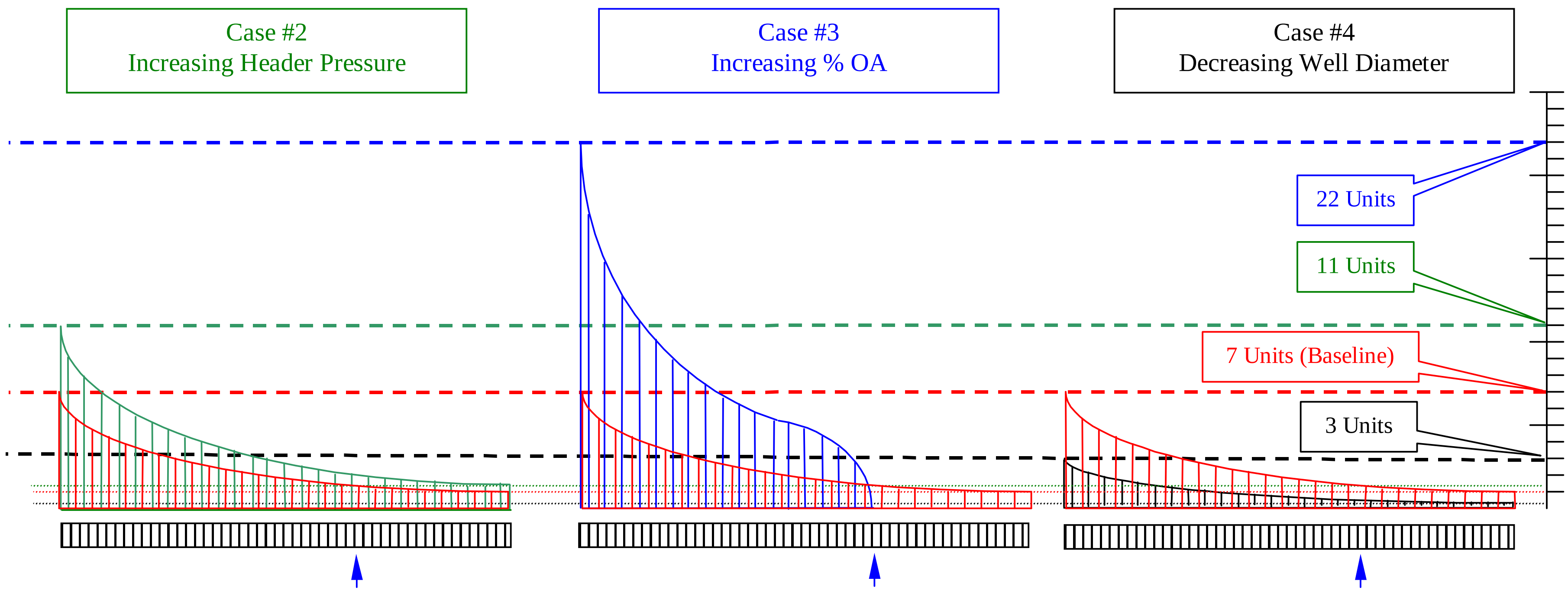
As a final thought to close and summarize the learnings that may be gleaned by this paper, it may well be advised to reiterate what was advised some pages ago:

Compressible distributed flow fluid dynamics can be, and typically is, very non-intuitive. Because so many degrees of freedom, or dimensions, are involved, it is extremely difficult to mentally consider all impacting variables concurrently, which must be done to properly formulate a correct conclusion of system performance. As the well/system and the conditions of installation become more and more complex, the ensuing mental juxtaposition of all information becomes even moreso difficult. Depending on the practitioner's level of knowledge and experience, it may be quite possible, even likely, that the well/system will operate exactly opposite of that thought. However, regardless of belief, expectation or intuition, the well/system will always operate in strict accordance with the Laws of Newtonian Physics.

Though these four examples were fairly simple and straightforward, it remains for the reader to consider how one would mentally analyze the impact on performance should not one but several concurrent changes be made to our baseline case. For example, suppose the baseline well were changed to 3% OA, its diameter increased to nominal 6" SDR-7 HDPE, header pressure increased to 13 psig, and the well were installed in fine sand such that the height of groundwater is 15 ft. above the well's centerline at the first series of slots and 10 ft. above it at the last slot. Since each of these changes impact the overall performance of our "new" well, each likewise will result in effects that are similar to, and conversely directly opposite or counteractive to, others. The question remains however, fundamental, what performance will really occur in our new well/system? [7]

[7] At this point, a hint may be in order... Regardless of what you *want* or *believe* will happen, Physics always wins! Good luck.

Figure #6



Case #2

- 400 ft. of 4" SDR-11 well screen
- Uniform 2% OA slotting
- Installed under 10 ft of groundwater
- Horizontal placement
- Applied pressure 15 psig

- Total, first slot and last slot flow rates increase
- Flow uniformity decreases
- Skew increases
- Increase in end of well flow slight

Case #3

- 400 ft. of 4" SDR-11 well screen
- Uniform 10% OA slotting
- Installed under 10 ft of groundwater
- Horizontal placement
- Applied pressure 10 psig

- Total and first slot flow rates increase
- Flow uniformity decreases
- Skew increases and is extreme
- End of well flow not possible

Case #4

- 400 ft. of 2" SDR-11 well screen
- Uniform 2% OA slotting
- Installed under 10 ft of groundwater
- Horizontal placement
- Applied pressure 10 psig

- Total, first slot and last slot flow rates decrease
- Flow uniformity increases
- Skew decreases
- End of well flow is very small

NOTES